CALIFORNIA RENEWABLES PORTFOLIO STANDARD (RPS) RENEWABLE GENERATION INTEGRATION COSTS ANALYSIS

PHASE I: ONE YEAR ANALYSIS OF EXISTING RESOURCES

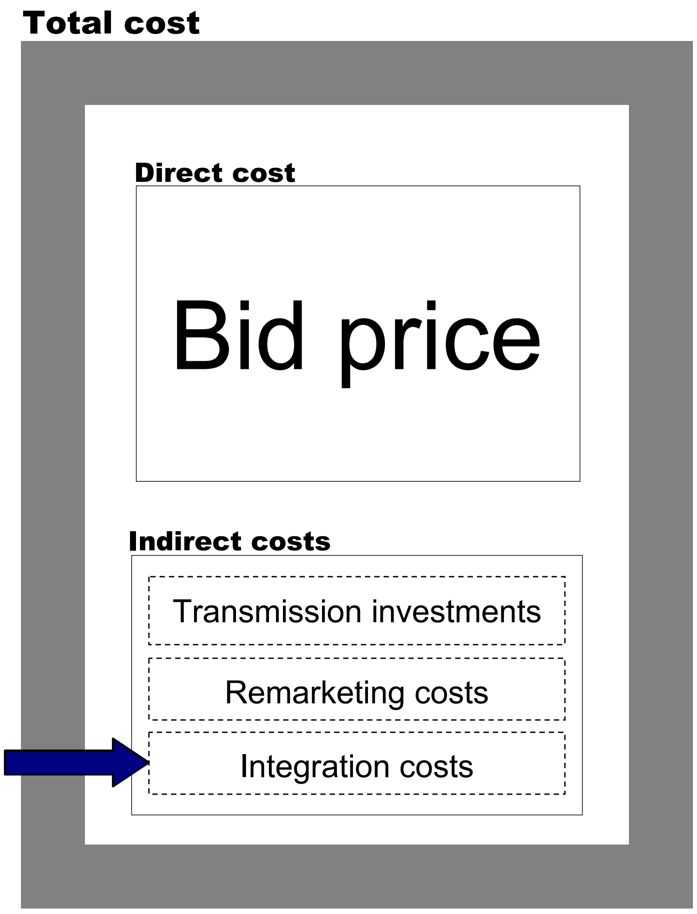
RESULTS AND RECOMMENDATIONS

Agenda

- Overview of the RPS Integration Costs Study
- Phase I Findings: Results and Methodologies
  - *Input Data*
  - *Capacity Credit*
  - *Regulation*
  - *Load Following*
- Open Discussion

California Renewables Portfolio Standard

"…the commission shall adopt, by rule, for all electrical corporations… A process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources."



Methods Group

- Dave Hawkins, *California ISO*
- Brendan Kirby, *Oak Ridge National Laboratory*
- Yuri Makarov, *California ISO*
- Michael Milligan, *National Renewable Energy Laboratory*
- Kevin Jackson, *Dynamic Design Engineering, Inc.*
- Henry Shiu, *California Wind Energy Collaborative*

Timeline

Phase I

- Develop integration costs analysis methodologies
  - Capacity Credit
  - Load Following
  - Regulation
- Apply methodology to a one year analysis of existing renewable and non-renewable generation in California

Phase II

- Identify and evaluate generator attributes affecting integration costs

Phase III

- Finalize integration costs methodology for application in RPS bid ranking

April 23, 2003
Report: Released proposed analysis methodology

April 29, 2003
Workshop: Presentation and discussion of proposed analysis methodology

September 12, 2003
Workshop: Presentation and discussion of methodology and findings of 2002 California analysis

October 9, 2003 to October 24, 2003
Public review of draft report

December 10, 2003
Report: Release of final report of Phase I results and recommendations

Timeline

Phase I

- Develop integration costs analysis methodologies
- Apply methodology to a one year analysis of existing renewable and non-renewable generation in California

Phase II

- Identify and evaluate generator attributes affecting integration costs

Phase III

- Finalize integration costs methodology for application in RPS bid ranking

Continuing analysis with additional data (more years, less aggregated)

Continuing development of a simplified capacity credit methodology.

Beginning study of secondary load following effects.

Beginning study of reserves.

Investigating the two renewable resources with the largest immediate growth potential: geothermal and wind.

- Studies for biomass, small hydro, and solar will be conducted at a future date.
- The studies are currently under revision and review.

Timeline

Phase I

- Develop integration costs analysis methodologies
- Apply methodology to a one year analysis of existing renewable and non-renewable generation in California

Phase II

- Identify and evaluate generator attributes affecting integration costs

Phase III

- Finalize integration costs methodology for application in RPS bid ranking
- Final methodology will:
  - *Use input data and analysis tools available in the public domain*
  - *Be fair, transparent, and coherent*
  - *Provide values that are representative of California*
  - *Be clearly defined and provide repeatable results*
  - *Be regularly updated to reflect California's current electrical portfolio*
- Completion in June 2004.

Feedback and Comments

- Website:
  - *http://cwec.ucdavis.edu/rpsintegration/*
- Mailing lists (subscribe via website):
  - *rpsintegration-workinggroup@cwec.ucdavis.edu*
    - an open mailing list for discussion of the development of the methodologies
  - *rpsintegration-announcements@cwec.ucdavis.edu*
    - an open mailing list announcing key events relevant to the study
- Formal comments:

California Energy Commission
Re: Docket No. 03-RPS-1078 and Docket No. 02-REN-1038
Docket Unit, MS-4
1516 Ninth Street
Sacramento, CA 95814-5504
E-mail:docket@energy.state.ca.us

Input Data

Input Data

- The data set for the analyses was composed of:
  - *One minute generation and CaISO system data*
  - *Ten minute supplemental energy market data*
  - *Hourly load and regulation market data*
- Data sources:
  - *Internal CaISO databases*
  - *Publicly accessible sources*
- Generation data was aggregated to satisfy confidentiality requirements.
  - *Future analyses require and will use non-aggregated data.*
- Data was manually inspected to correct errors such as spikes and dropouts.

CalSO Plant Information "PI" Data System

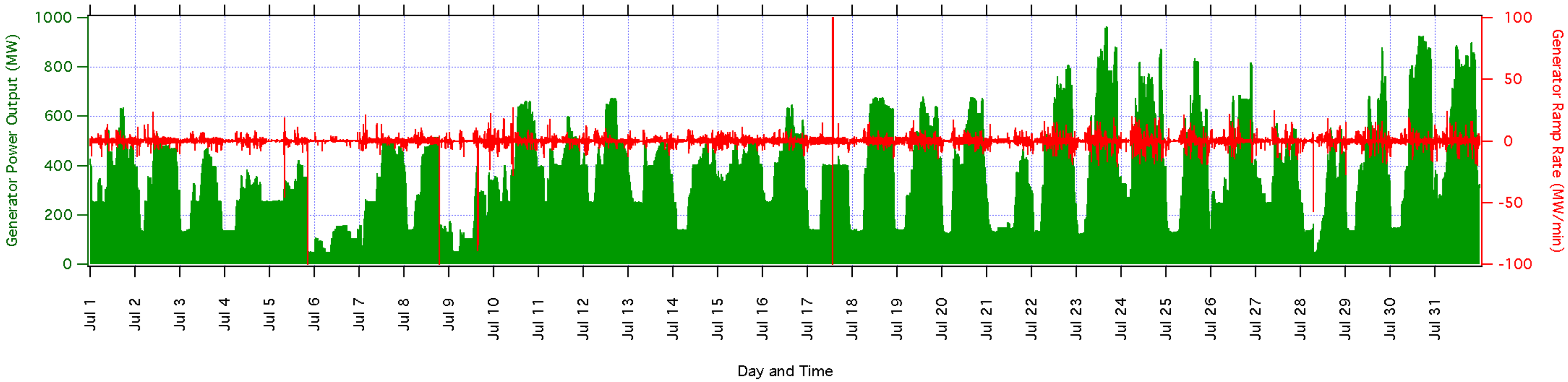
- Standardized commercial database system.
- Records data obtained from generators throughout the state.
- Database contains over 180,000 data fields.
- Data compression is used to minimize storage.
- Units are identified by specific tags ("PI tags").
- Data was downloaded through a Microsoft Excel interface and output as two files per day.

PI Data Extracted

- Annual One Minute Data (525,600 data points)
- System Conditions
  - *Total Load and Generation (MW)*
  - *Actual and Scheduled Frequency (Hz)*
  - *Actual and Scheduled Interchange (MW)*
  - *Dynamic Interchange Schedule (MW)*
  - *Area Control Error (MW)*
  - *Total Regulation (MW)*
  - *Deviation from Preferred Operating Point (MW)*
- Representative Conventional Generators
  - *Eleven Generators of Various Types and Sizes*
  - *Automatically Controlled Units*
  - *Dispatcher Controlled Units*
- Representative Renewable Generators
  - *Biomass*
  - *Geothermal*
  - *Solar*
  - *Wind (state total and regional)*

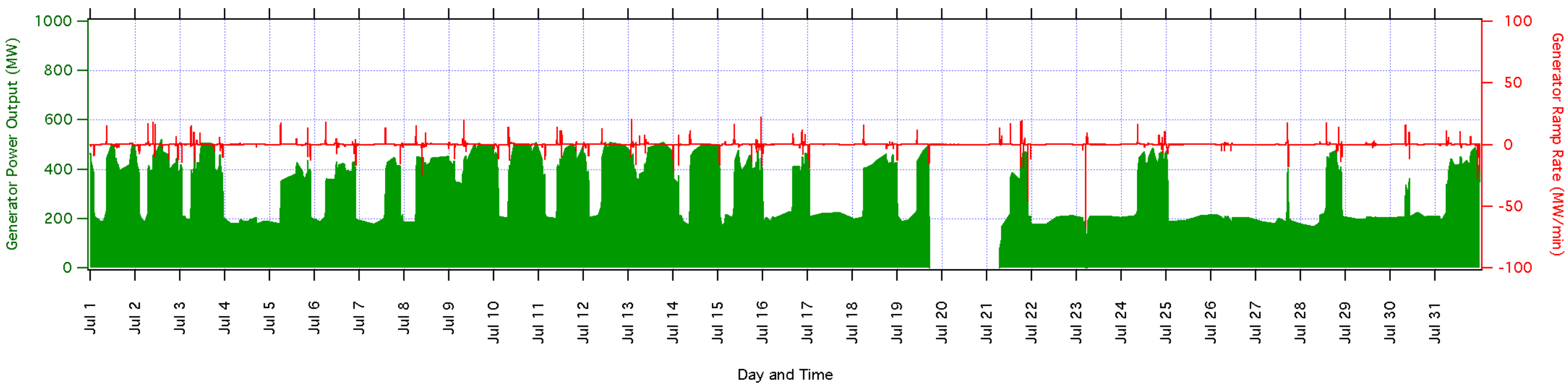
Automatically Controlled Generators

- Movements are controlled automatically by a computerized control system.



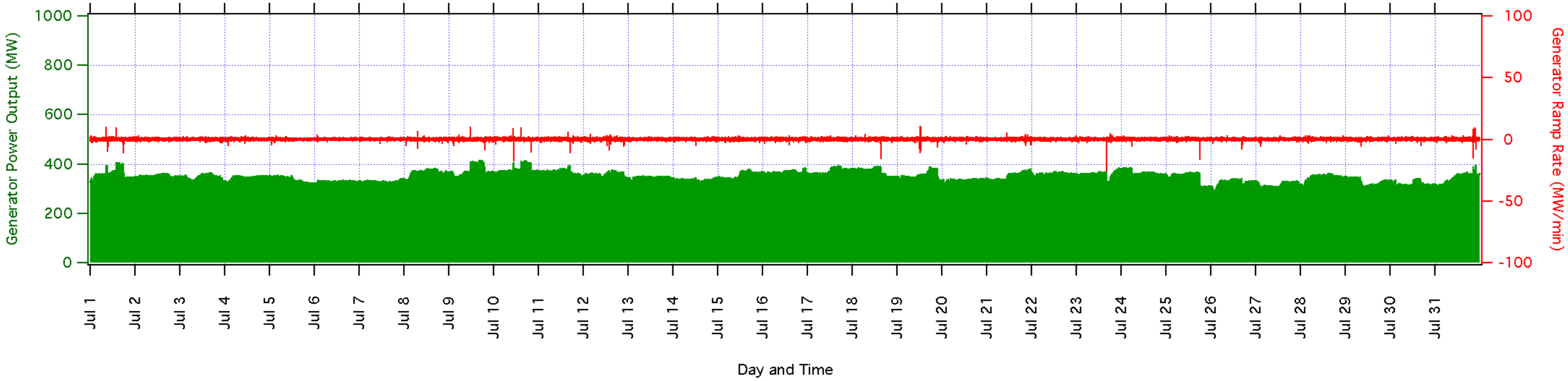
Dispatcher Controlled Generators

- Movements controlled by dispatcher instructions.



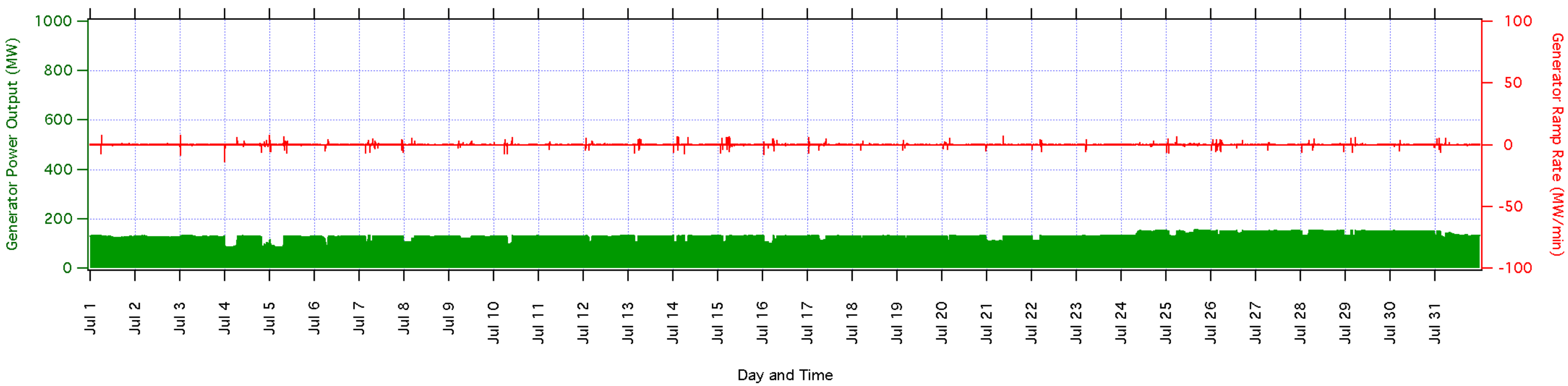
Biomass

- Aggregation of several generation units.



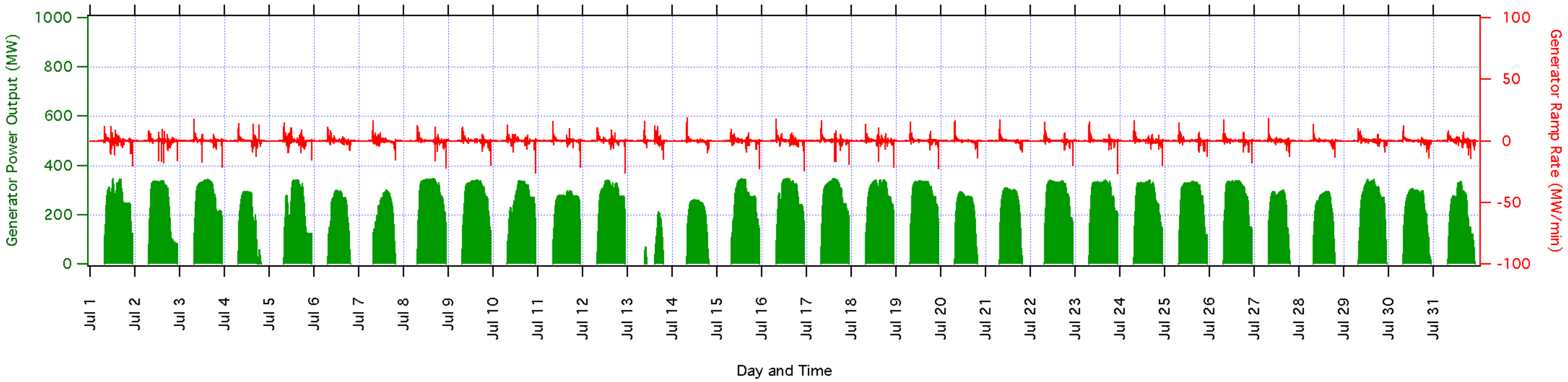
Geothermal

- Aggregation of several generation units.



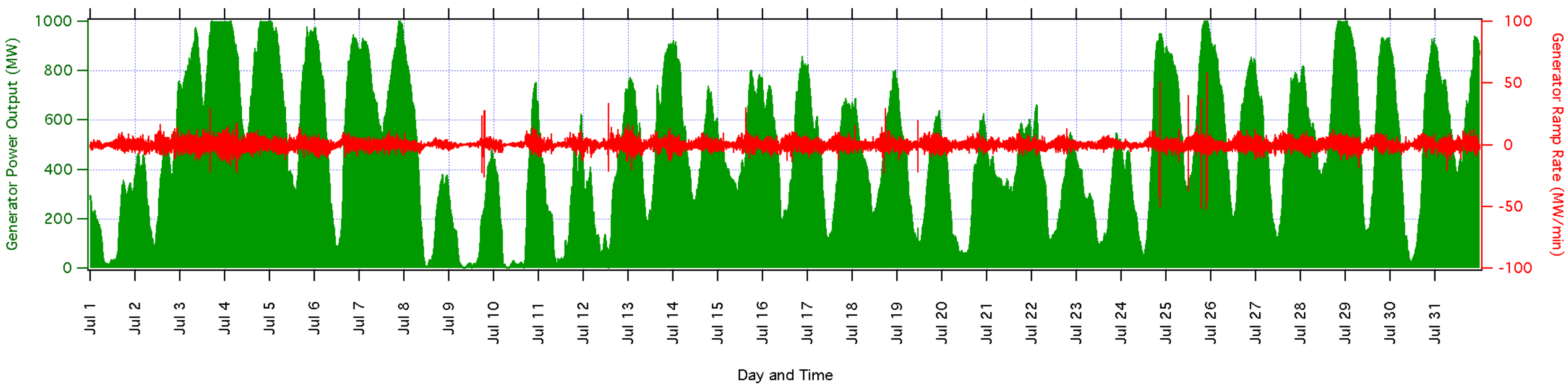
Solar

- Aggregation of several generation units.



Wind

- Aggregation of several generation units.
- Statewide total.
- Regional subtotals
  - *Altamont*
  - *San Gorgonio*
  - *Tehachapi*

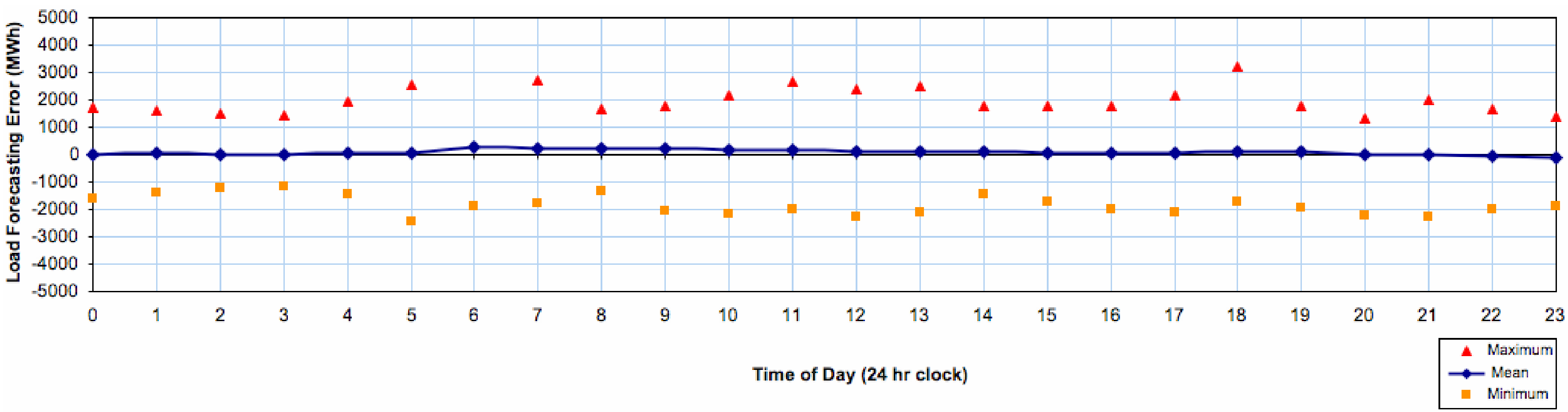


Publicly Accessible Data

- OASIS: Open Access Same-Time Information System
  - *Public, web-based system for selected CaISO data.*
    - http://oasis.caiso.com/
  - *Load forecasts and schedules.*
  - *Regulation capacity purchases.*
  - *Load following energy purchases.*
- CaISO Non-Operational Generating Units Reports
  - *Daily generator outage reports.*

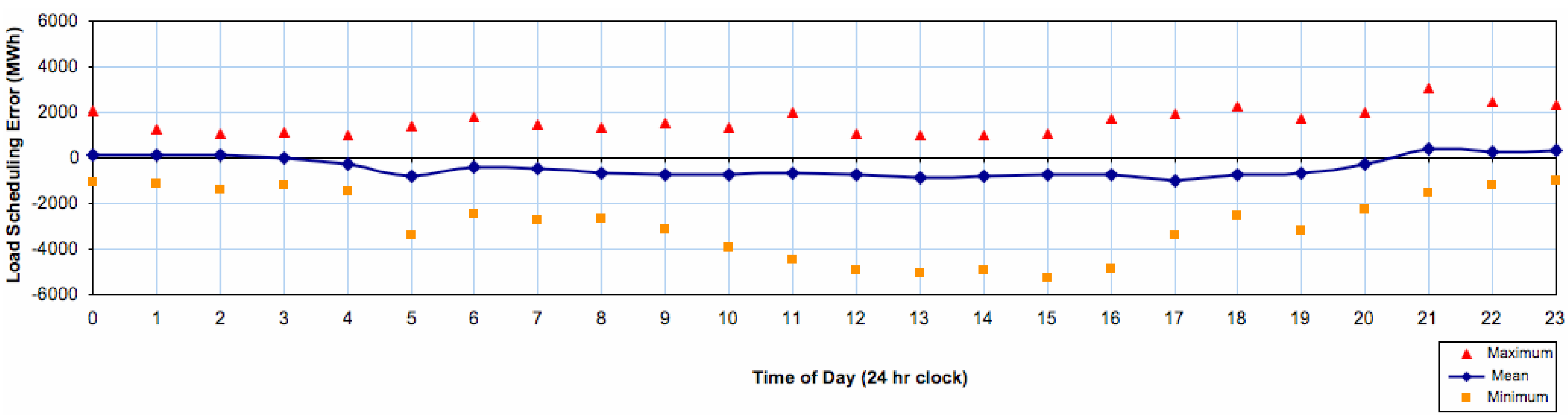
Forecast Hour Ahead Load

- CaISO forecast of load for hour ahead market.
- Load is estimated 150 minutes ahead of time.
- Forecasted load can be about 2200 MW less than actual load for some hourly time periods.
- Forecasted load is nearly unbiased and average forecasting error is close to zero.

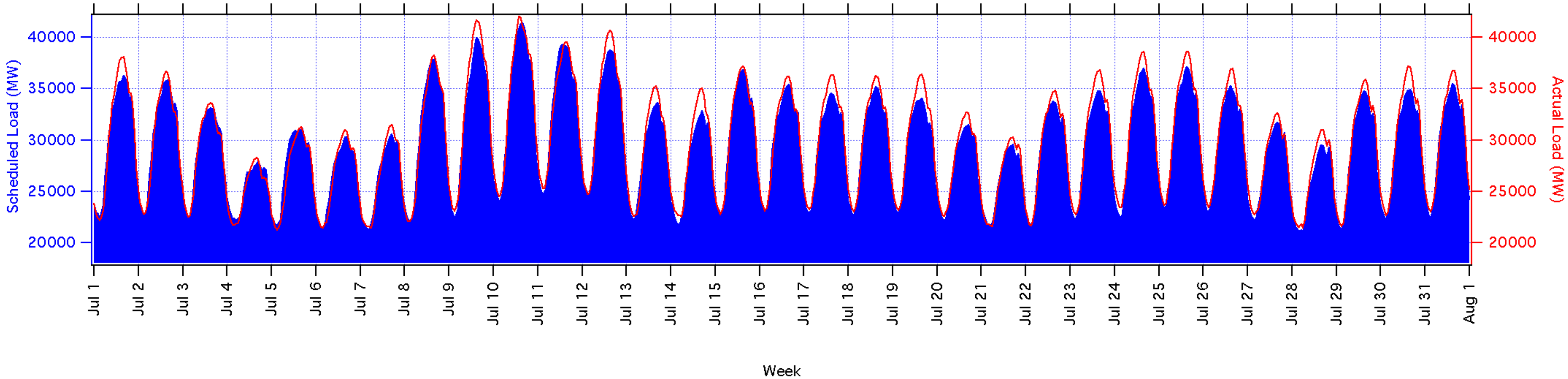


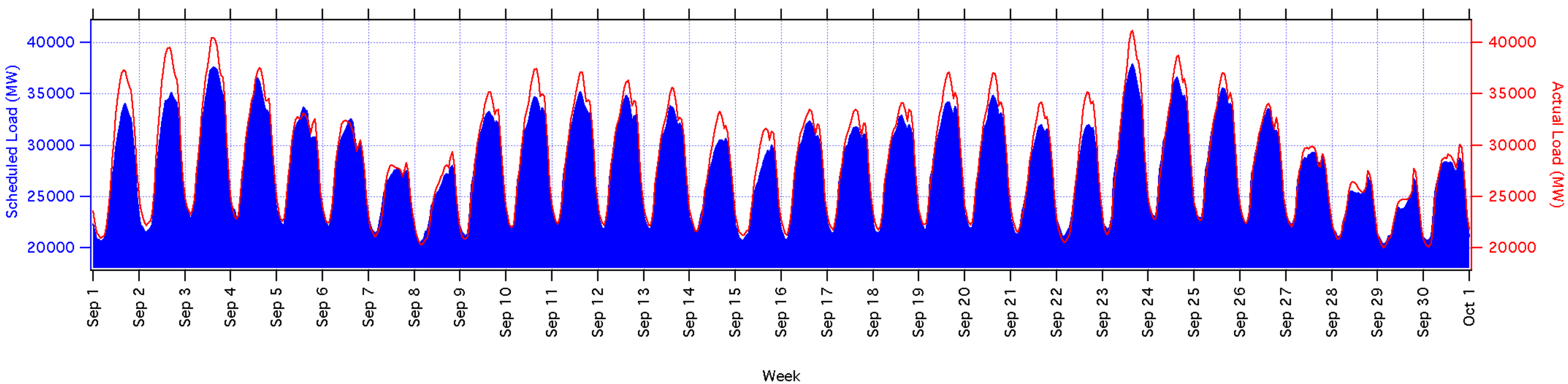
Scheduled Hour Ahead Load

- Hour ahead schedules are submitted to CalSO by the scheduling coordinators.
- Scheduled load can be as much as 5000 MW less than the actual load during some hours of the year.
- The load scheduling error is defined as the scheduled load minus the actual load.
- Scheduling error is most negative during the day.



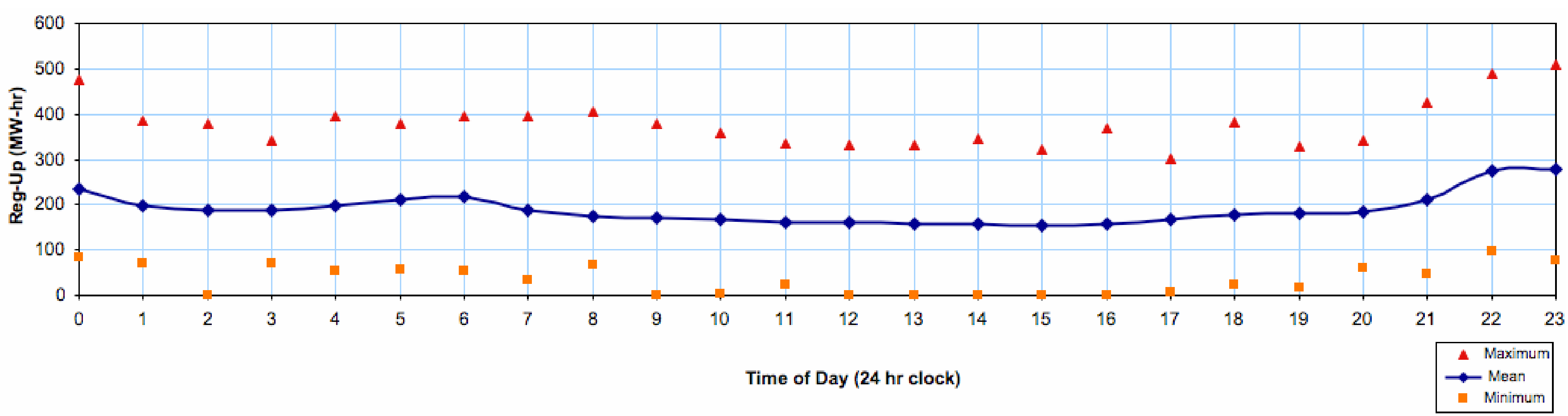
Scheduled Hour Ahead Load





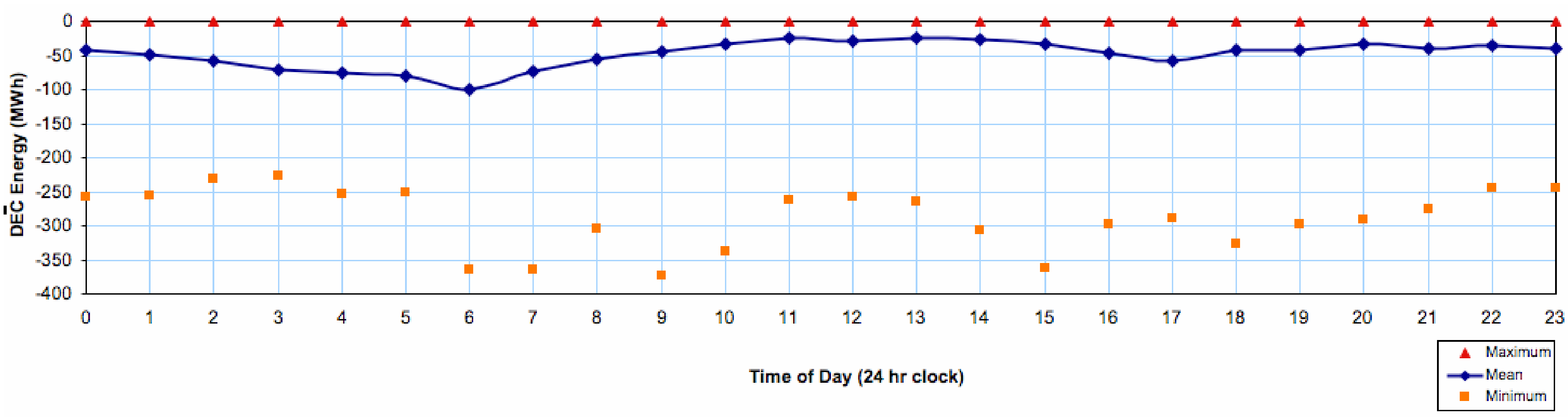
Regulation Purchases

- Regulation is an ancillary service which is purchased hourly.
- One MW of regulation capacity service provided for one hour is denoted as one MW-hr (Note: Regulation is a capacity service and one MW-hr of capacity is not equivalent to one MWh of energy).
- CaISO purchases two kinds of regulation service.
  - *Regulation up*
  - *Regulation down*
- The OASIS data contains both the amount and the price for each of the services procured for every hour of the year.



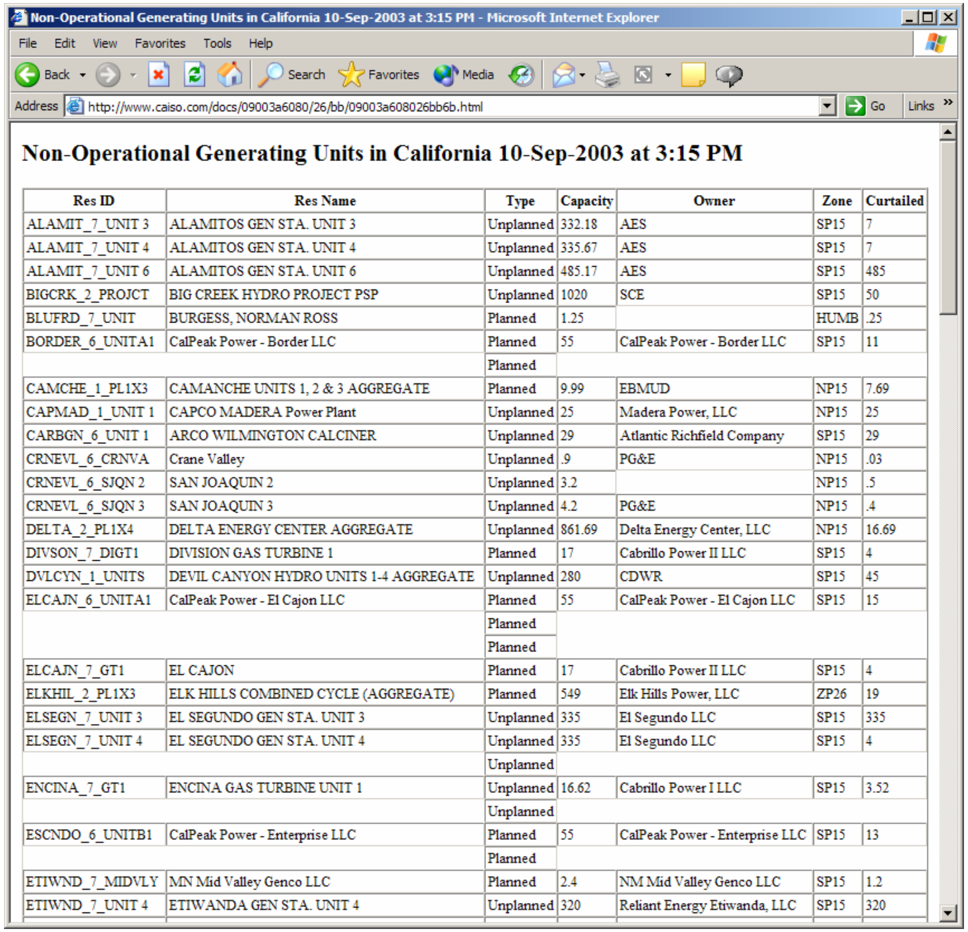
Supplemental Energy Purchases

- The supplemental energy market provides two types of purchases.
  - *Incremental (INC) energy*
  - *Decremental (DEC) energy*
- The supplemental energy market operates every ten minutes, but data were averaged to hourly values for use in this analysis.



Generator Outage Data

- Publicly available reports on CalSO website
- Reports back to January 1, 2001
- Four reports published each day
- Includes:
  - *Specific generator*
  - *Amount of capacity curtailed*
  - *Planned/unplanned outage*



Non-Operational Generating Units in California 10-Sep-2003 at 3:15 PM

Res ID	Res Name	Type	Capacity	Owner	Zone	Curtailed
ALAMIT_7_UNIT 3	ALAMITOS GEN STA. UNIT 3	Unplanned	332.18	AES	SP15	7
ALAMIT_7_UNIT 4	ALAMITOS GEN STA. UNIT 4	Unplanned	335.67	AES	SP15	7
ALAMIT_7_UNIT 6	ALAMITOS GEN STA. UNIT 6	Unplanned	485.17	AES	SP15	485
BIGCRK_2_PROJCT	BIG CREEK HYDRO PROJECT PSP	Unplanned	1020	SCE	SP15	50
BLUFRD_7_UNIT	BURGESS, NORMAN ROSS	Planned	1.25		HUMB	.25
BORDER_6_UNITA1	CalPeak Power - Border LLC	Planned	55	CalPeak Power - Border LLC	SP15	11
		Planned				
CAMCHE_1_PL1X3	CAMANCHE UNITS 1, 2 & 3 AGGREGATE	Planned	9.99	EBMUD	NP15	7.69
CAPMAD_1_UNIT 1	CAPCO MADERA Power Plant	Unplanned	25	Madera Power, LLC	NP15	25
CARBGN_6_UNIT 1	ARCO WILMINGTON CALCINER	Unplanned	29	Atlantic Richfield Company	SP15	29
CRNEVL_6_CRNVA	Crane Valley	Unplanned	.9	PG&E	NP15	.03
CRNEVL_6_SJQN 2	SAN JOAQUIN 2	Unplanned	3.2		NP15	.5
CRNEVL_6_SJQN 3	SAN JOAQUIN 3	Unplanned	4.2	PG&E	NP15	.4
DELTA_2_PL1X4	DELTA ENERGY CENTER AGGREGATE	Unplanned	861.69	Delta Energy Center, LLC	NP15	16.69
DIVSON_7_DIGT1	DIVISION GAS TURBINE 1	Planned	17	Cabrillo Power II LLC	SP15	4
DVLCYN_1_UNITS	DEVIL CANYON HYDRO UNITS 1-4 AGGREGATE	Unplanned	280	CDWR	SP15	45
ELCAJN_6_UNITA1	CalPeak Power - El Cajon LLC	Planned	55	CalPeak Power - El Cajon LLC	SP15	15
		Planned				
		Planned				
ELCAJN_7_GT1	EL CAJON	Planned	17	Cabrillo Power II LLC	SP15	4
ELKHIL_2_PL1X3	ELK HILLS COMBINED CYCLE (AGGREGATE)	Planned	549	Elk Hills Power, LLC	ZP26	19
ELSEGN_7_UNIT 3	EL SEGUNDO GEN STA. UNIT 3	Unplanned	335	El Segundo LLC	SP15	335
ELSEGN_7_UNIT 4	EL SEGUNDO GEN STA. UNIT 4	Unplanned	335	El Segundo LLC	SP15	4
		Unplanned				
ENCINA_7_GT1	ENCINA GAS TURBINE UNIT 1	Unplanned	16.62	Cabrillo Power I LLC	SP15	3.52
		Unplanned				
ESCNDO_6_UNITB1	CalPeak Power - Enterprise LLC	Planned	55	CalPeak Power - Enterprise LLC	SP15	13
		Planned				
ETIWND_7_MIDVLY	MN Mid Valley Genco LLC	Planned	2.4	NM Mid Valley Genco LLC	SP15	1.2
ETIWND_7_UNIT 4	ETIWANDA GEN STA. UNIT 4	Unplanned	320	Reliant Energy Etiwanda, LLC	SP15	320

Capacity Credit Analysis

Overview of Approach

Method:

- *Reliability model used to calculate effective load carrying capability (ELCC) for each intermittent renewable generator*
- *For each intermittent renewable generator (solar, wind), calculated 24 statistical distributions per week, one for each hour of the day (1,248 distributions/year)*
- *Based on discussion at September 2003 workshop, the 24 distributions were calculated on a monthly basis (288 distributions/year)*
- *One geothermal case also used this method*
- *Each distribution based on actual generation data*

- Non-intermittent renewable technologies require different representation in model
- Use capacity and forced outage data, similar to conventional generators

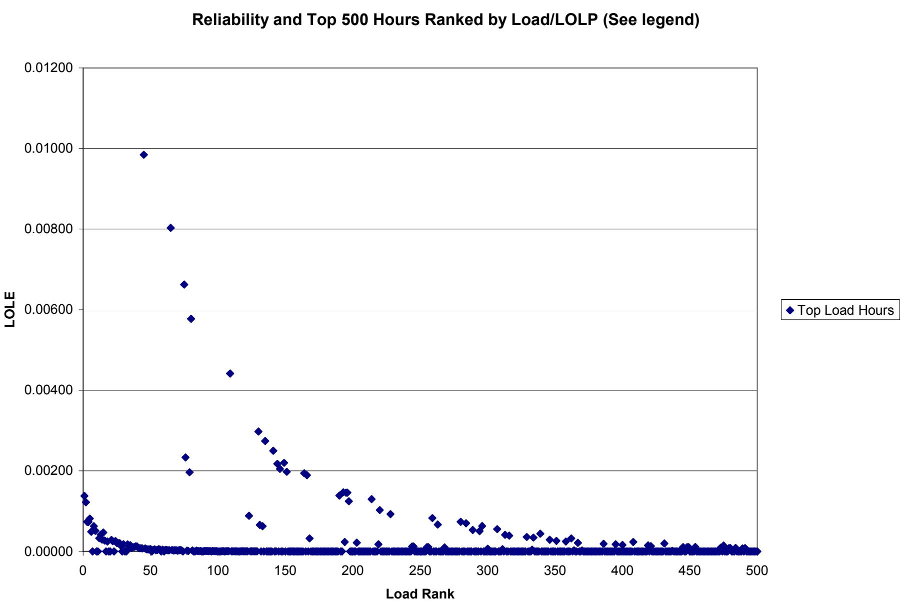
- Method
  - *Calibrated system load so that standard risk (1 day/10 years) LOLE with renewables, and without hypothetical gas benchmark unit*
  - *Compared each renewable generator, one at a time, to a hypothetical gas benchmark plant*
  - *This was done by removing the renewable plant of interest, then substituting the hypothetical gas plant at several alternative sizes until the reliability target was met*

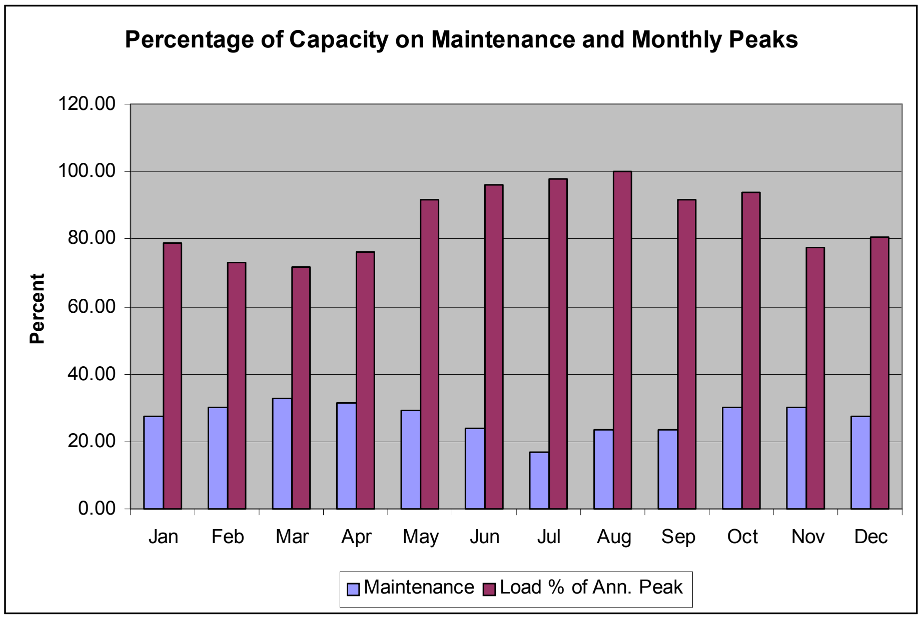
Overview of Approach

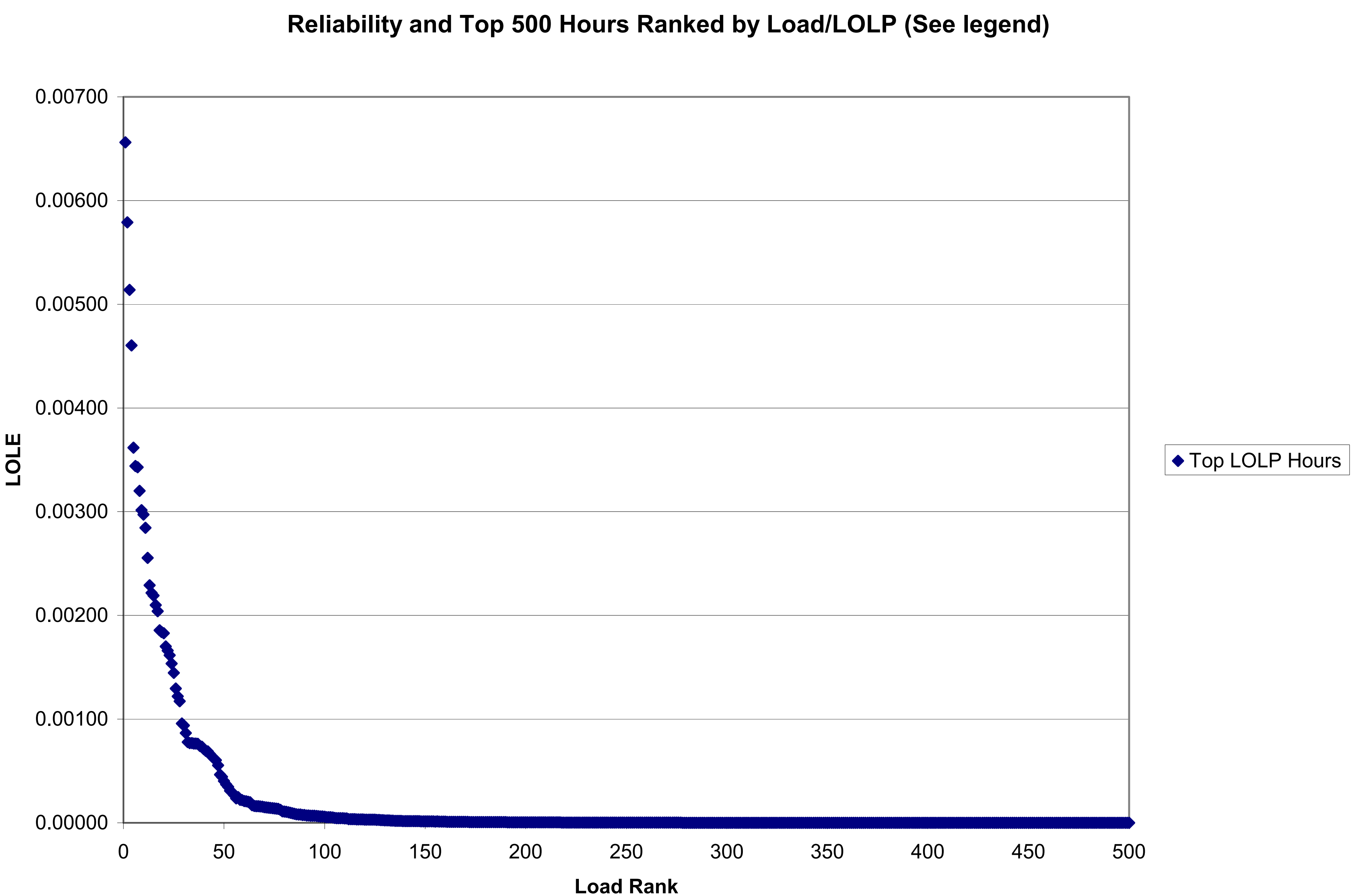
- Data:
  - *Conventional generator capacity and forced outage rates from Resource Data International's (RDI) BaseCase database (unable to obtain data from CalSO)*
  - *Maintenance outage schedules derived from data on CalSO web site*
  - *Renewable data from CalSO PI system*

Disparity Between High-Load Hours and High-Risk Hours

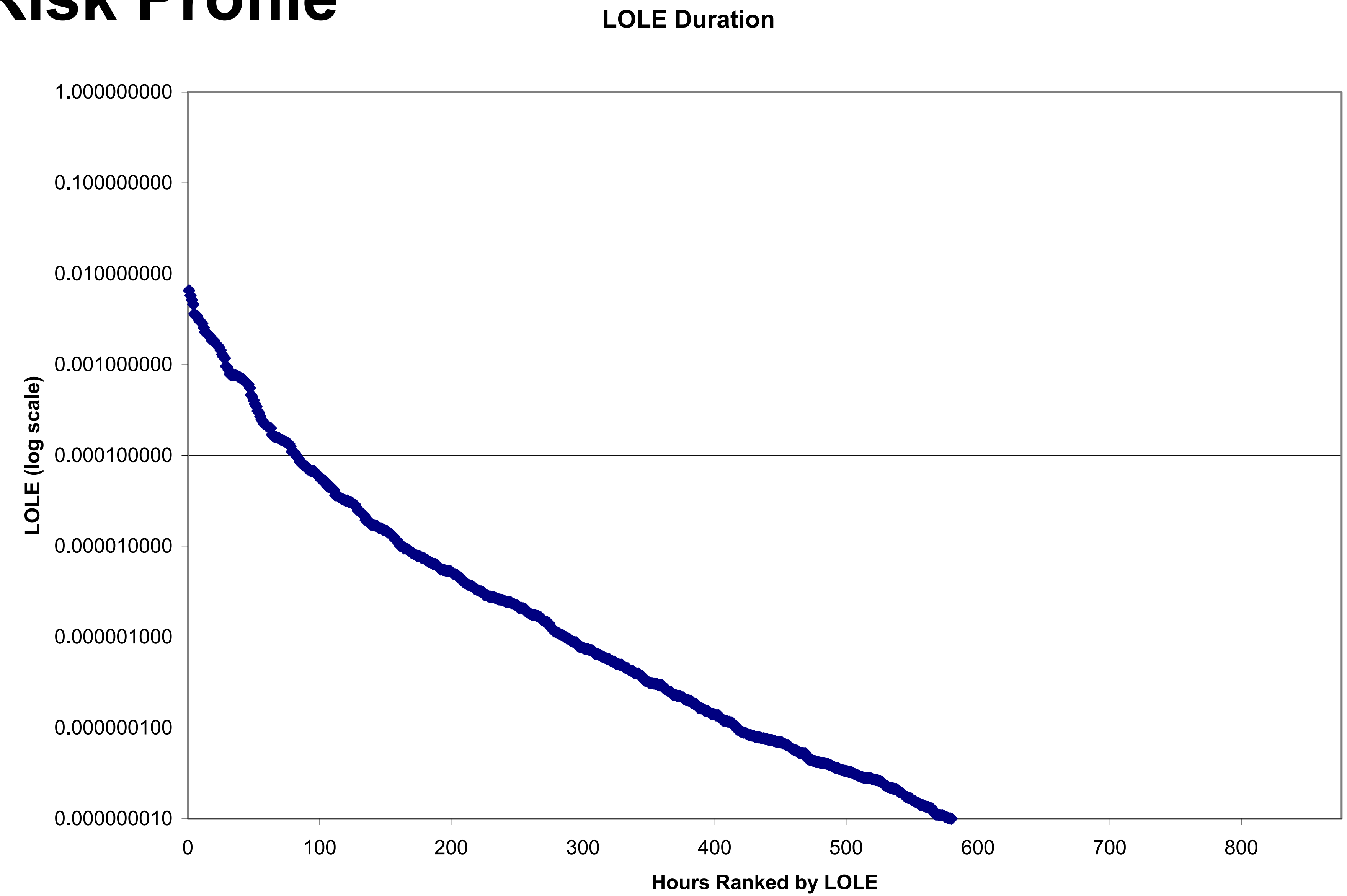
- Caused by uncoordinated maintenance scheduling
- Peak hour occurs in August
- Highest risk hours in October when many units out for maintenance
- Recommend a separate study of the CA system to determine impacts of alternative maintenance scheduling to minimize risk
- Based on discussion at September 2003 workshop, maintenance outages were removed from the reliability calculation



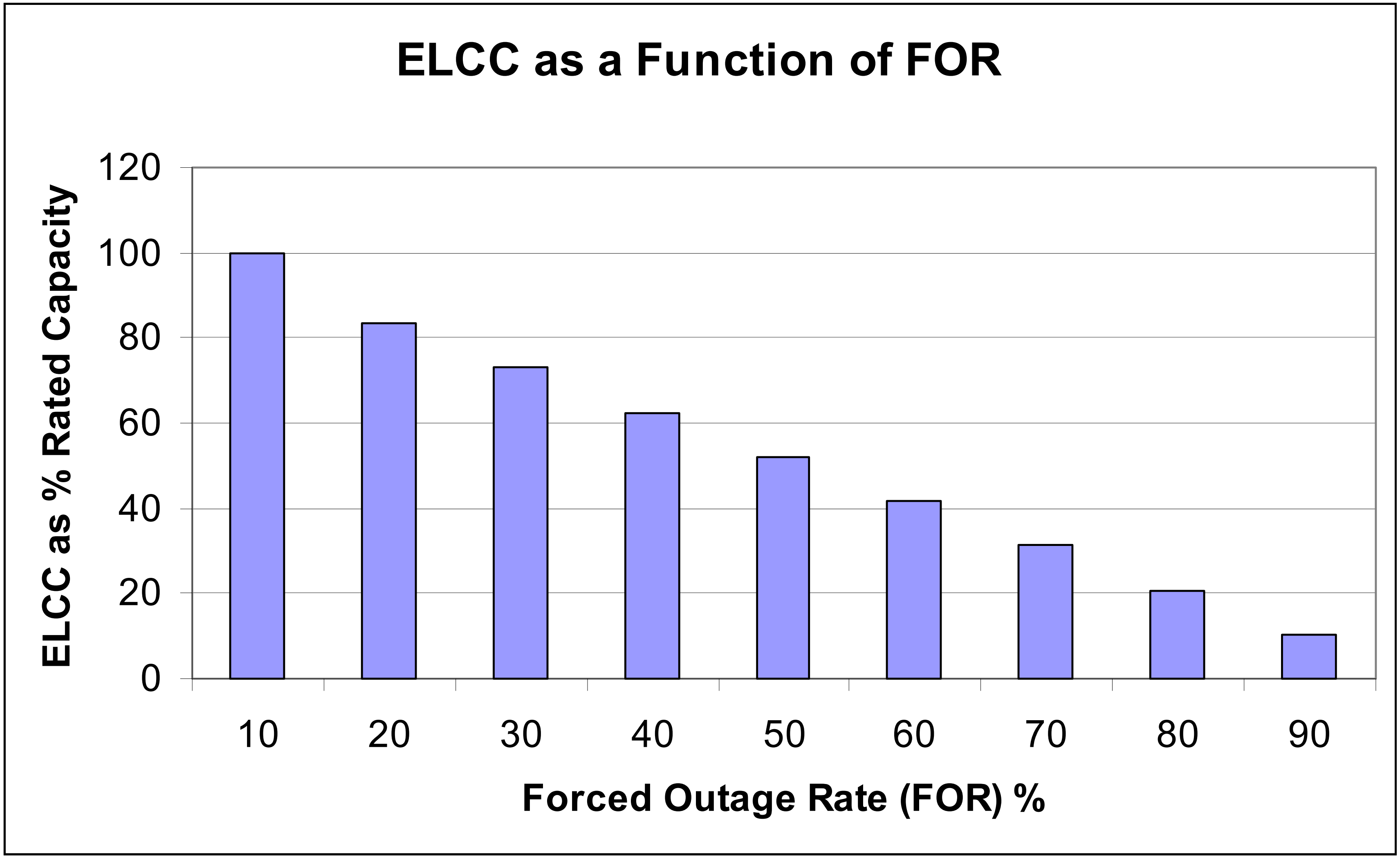



Reliability and Top 500 Hours Ranked by Load/LOLP (See legend)
0.00700
0.00600
0.00500
0.00400
0.00300
0.00200
0.00100
0.00000
LOLE
0
50
100
150
200
250
300
350
400
450
500
Load Rank
Top LOLP Hours

Risk Profile



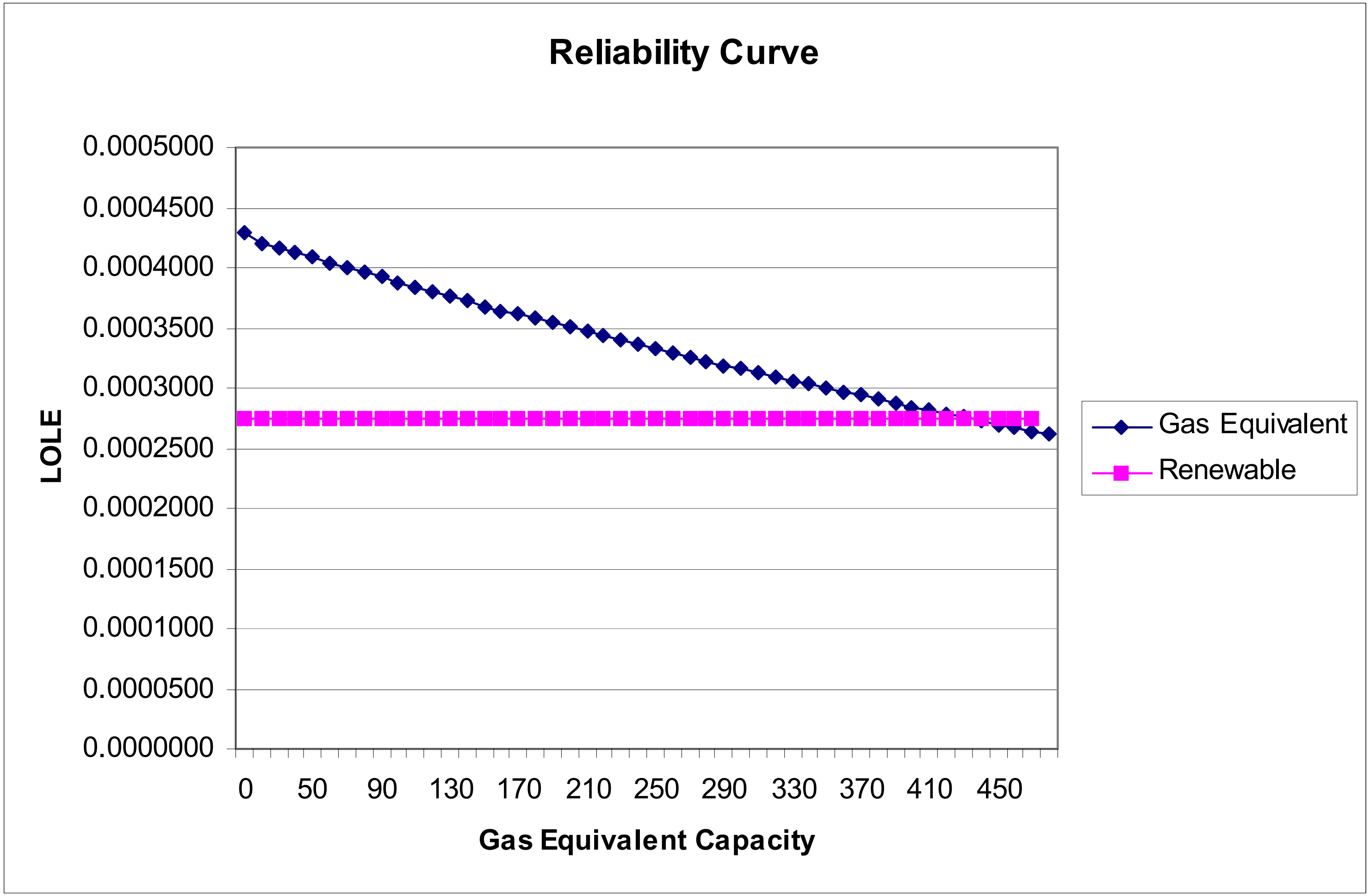
Generic 100 MW Plant



ELCC Results

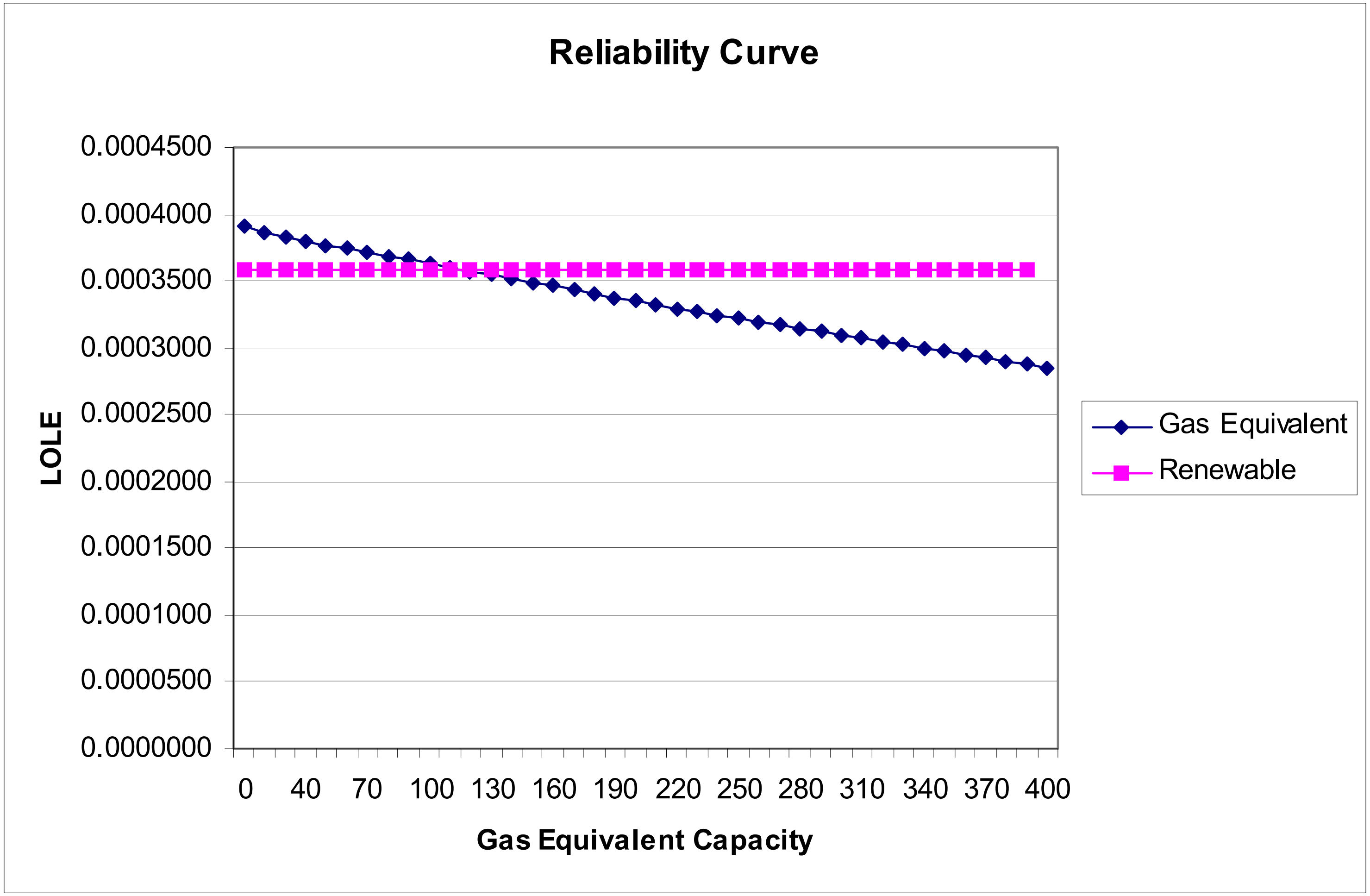
Biomass

ELCC = 97.8%



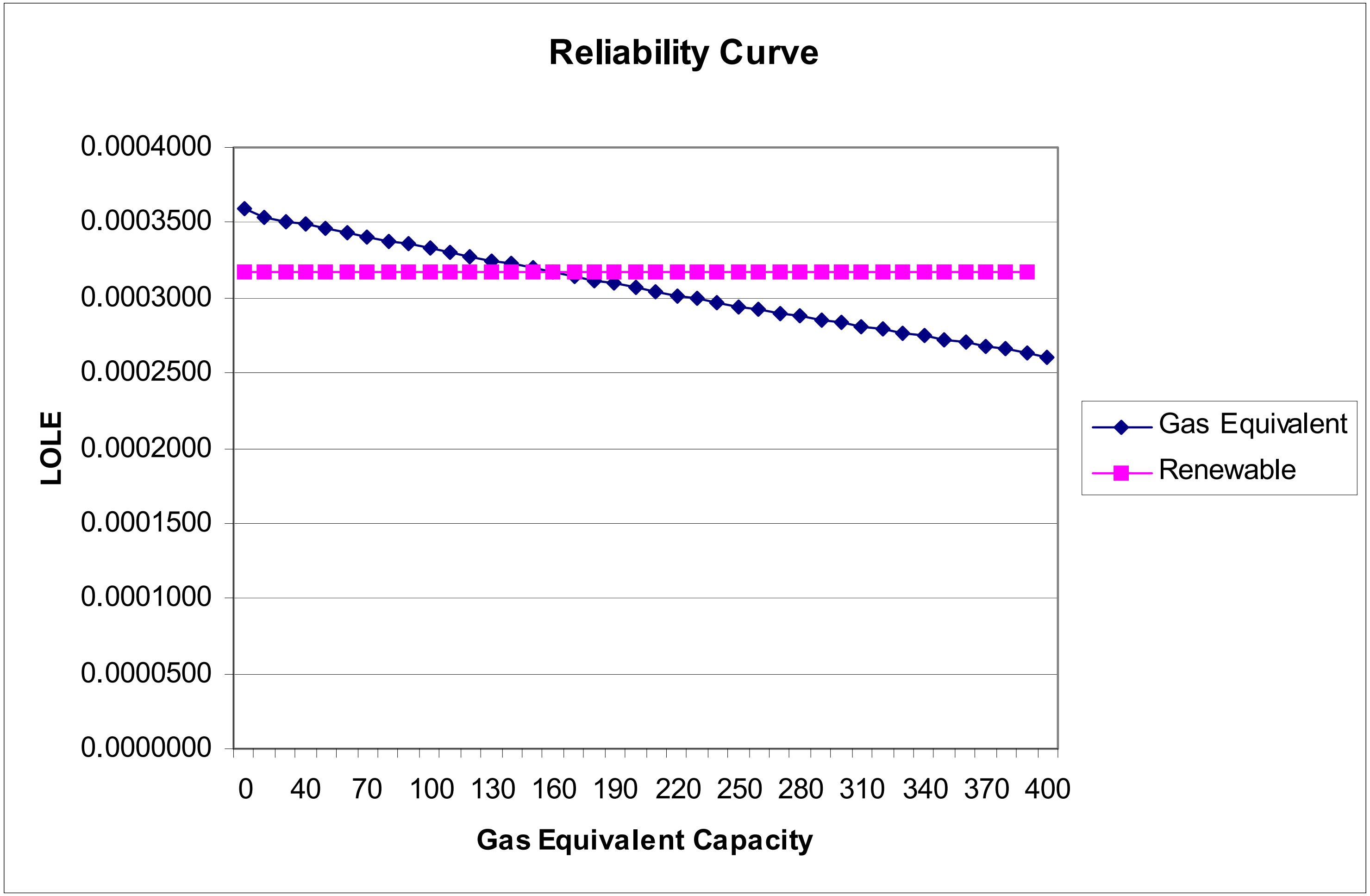
Geothermal Based on Actual Hourly Data

ELCC = 73.6%



Example Geothermal, No Steam Constraint

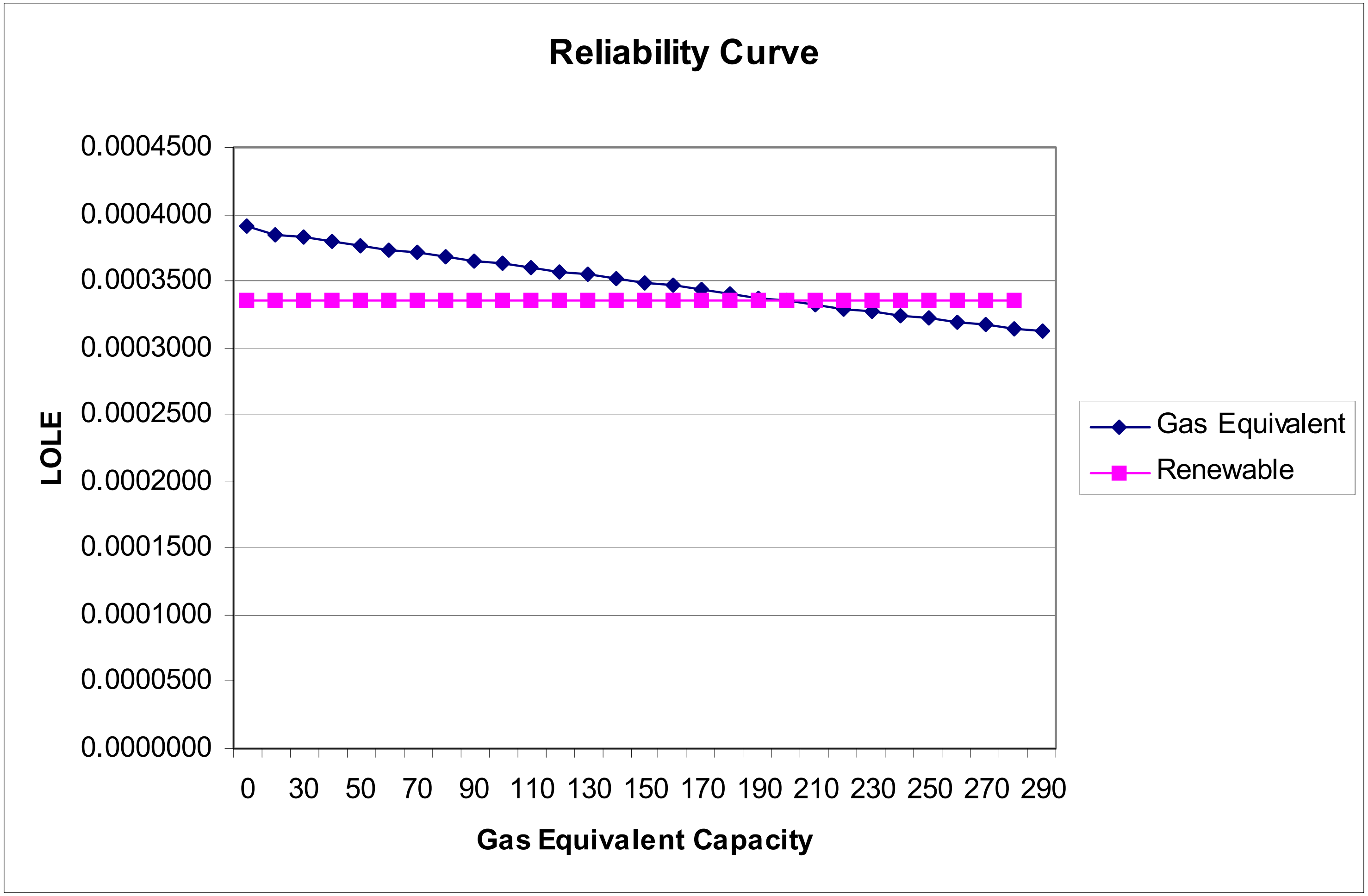
ELCC = 102.3% (of gas reference plant)

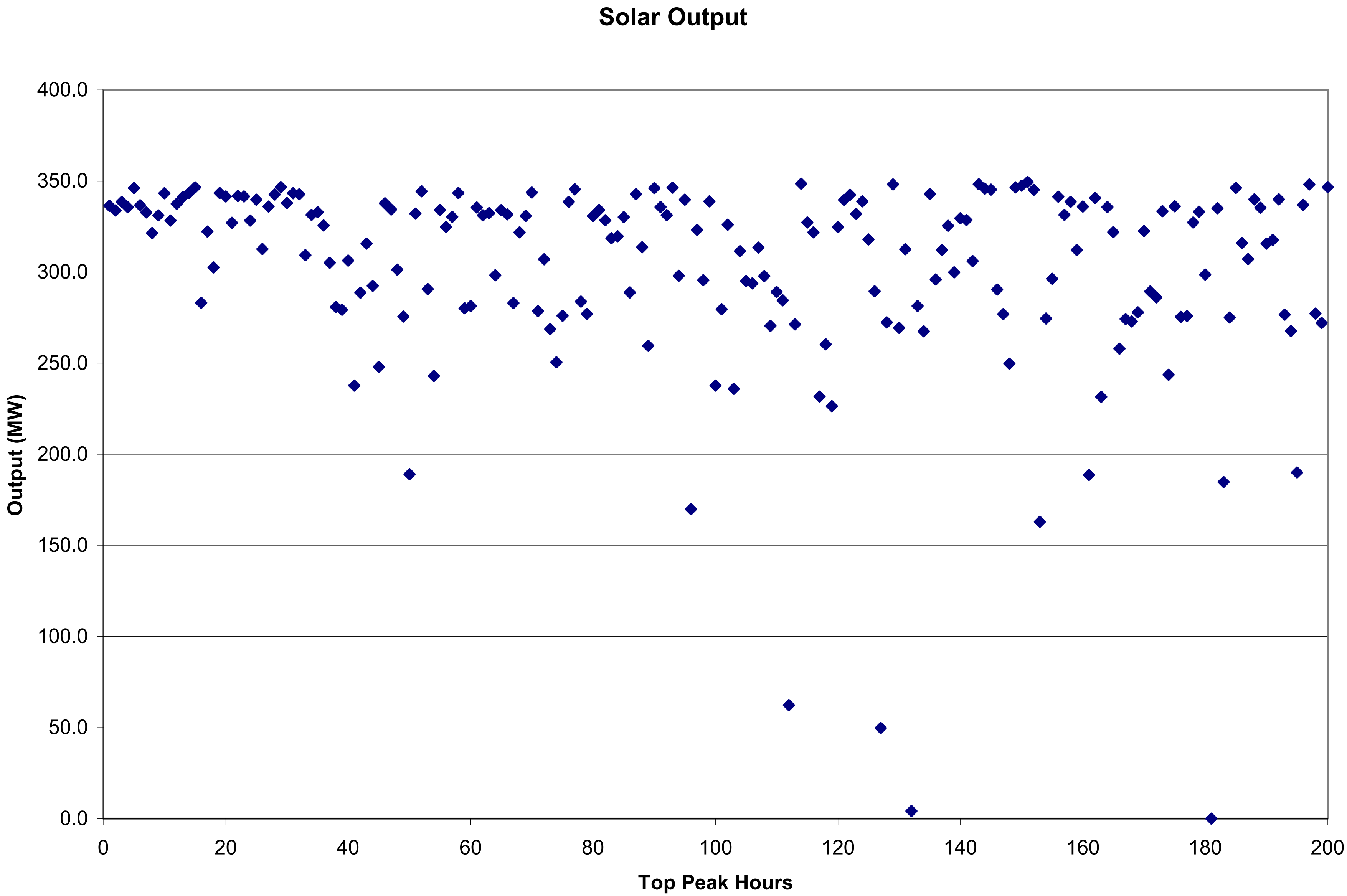


Solar

ELCC = 56.6%

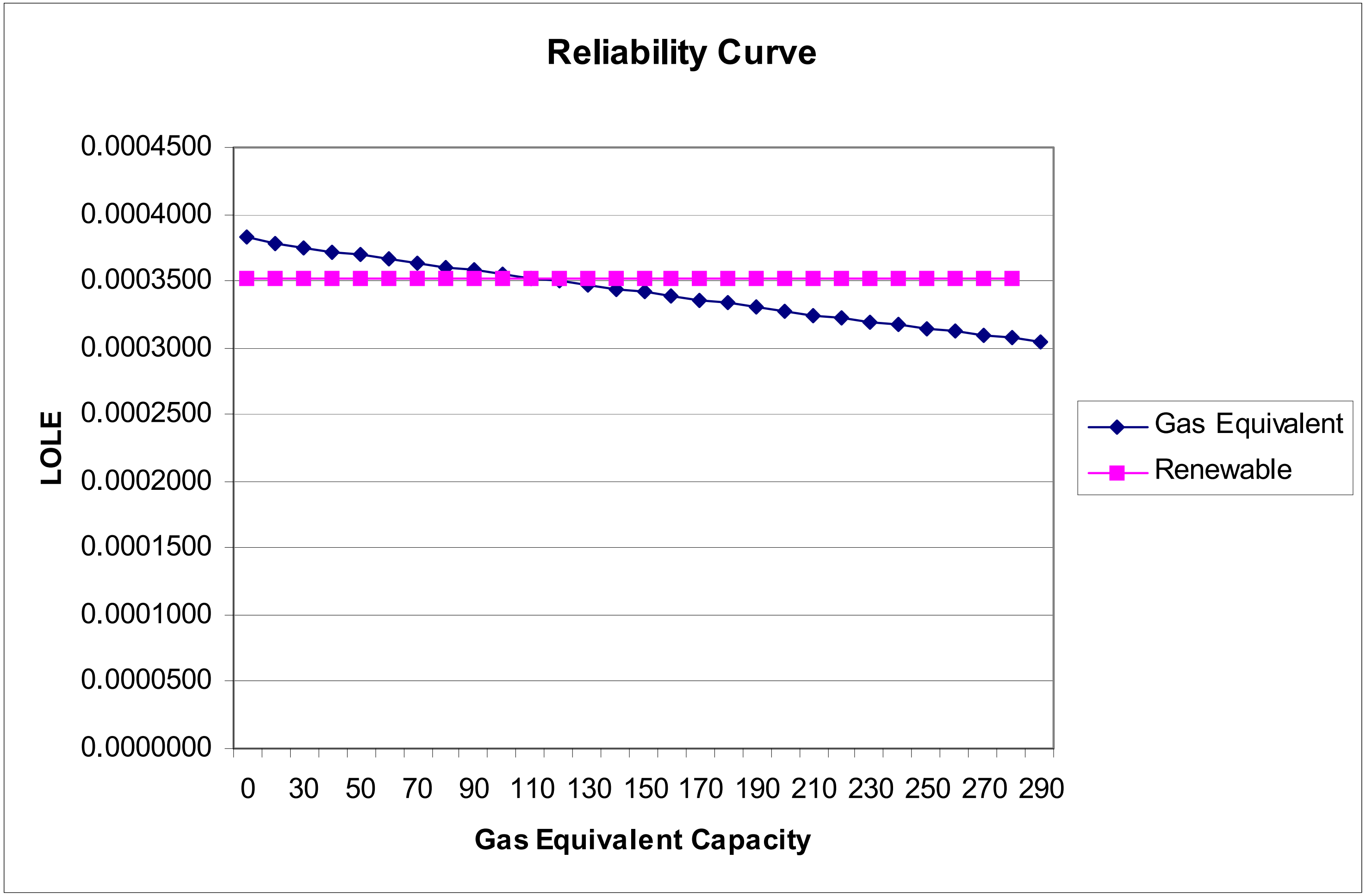
- **This value is not recommended for adoption.**




Solar Output
Output (MW)
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
0
20
40
60
80
100
120
140
160
180
200
Top Peak Hours

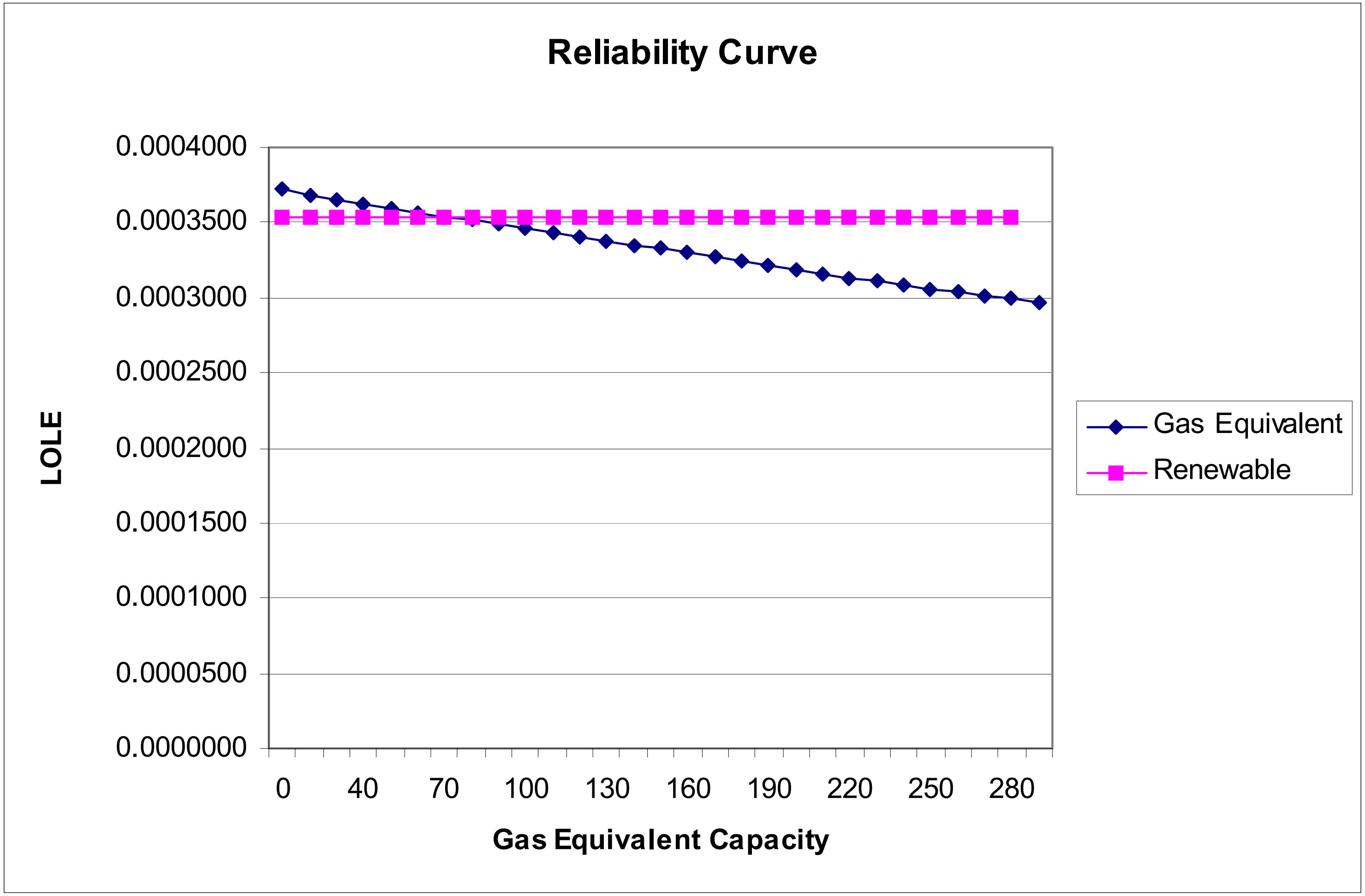
Wind: Altamont

ELCC = 26.0%



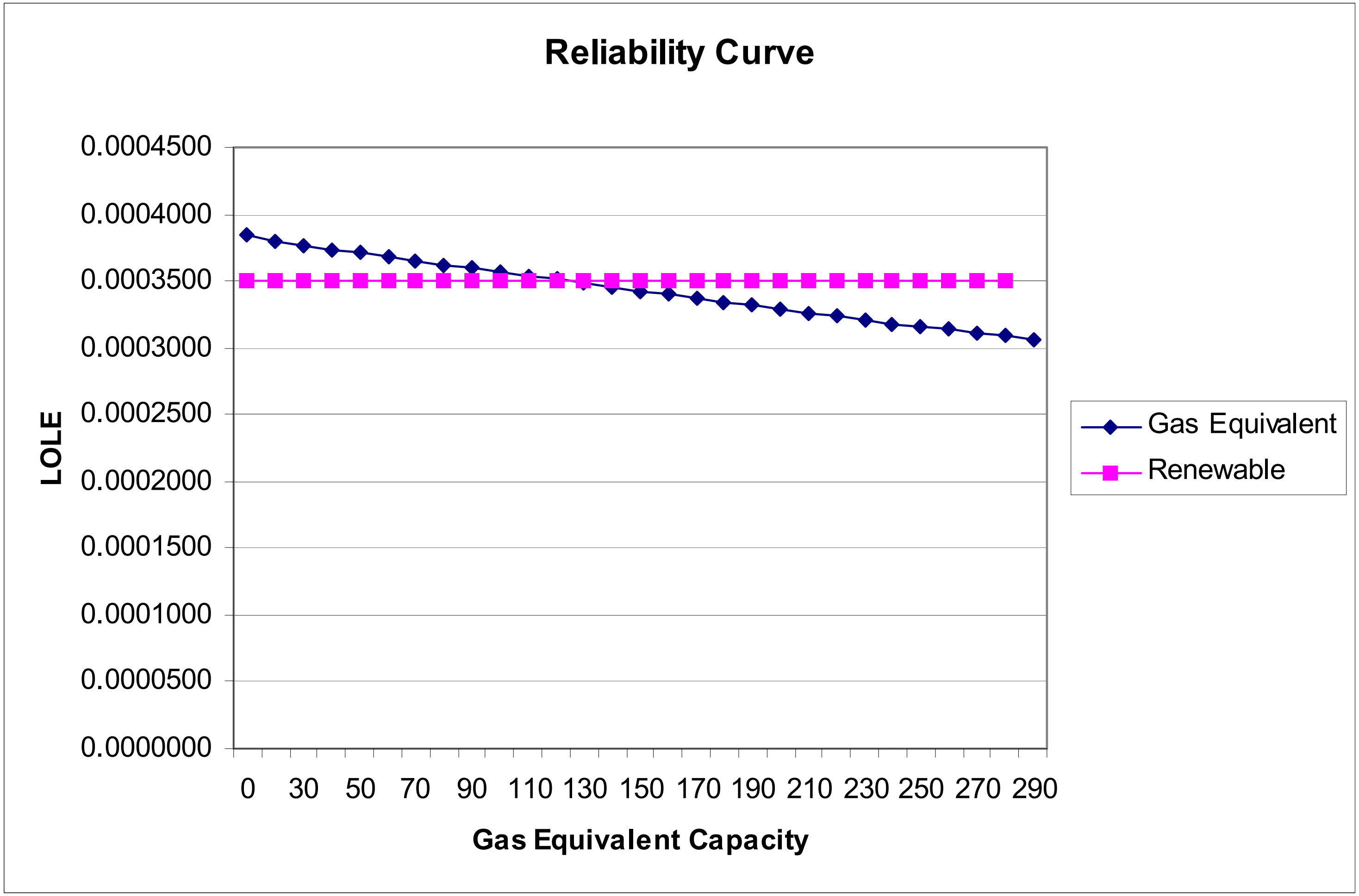
Wind: San Gorgonio

ELCC = 23.9%

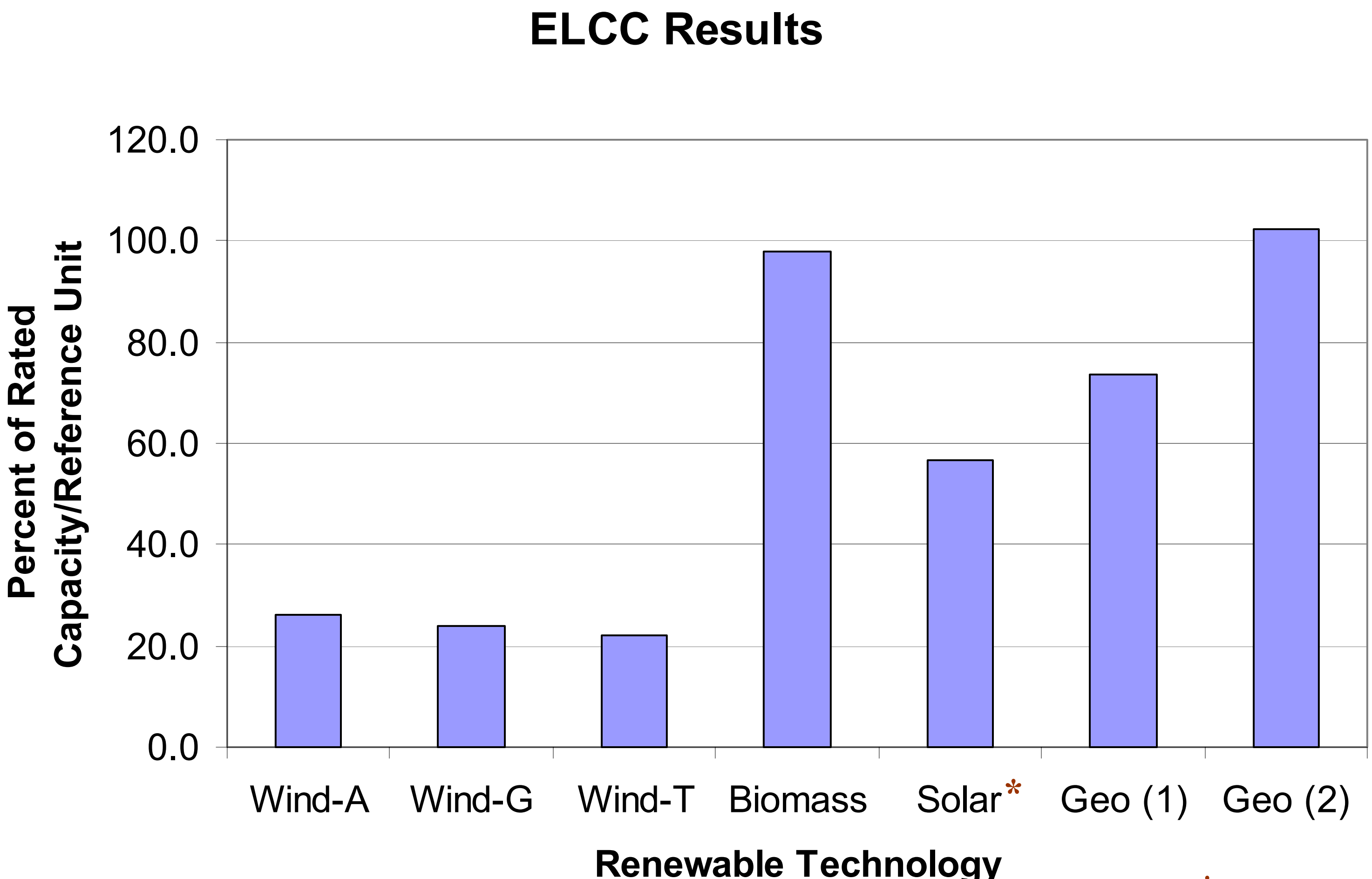


Wind: Tehachapi

ELCC = 22.0%



Summary by Technology

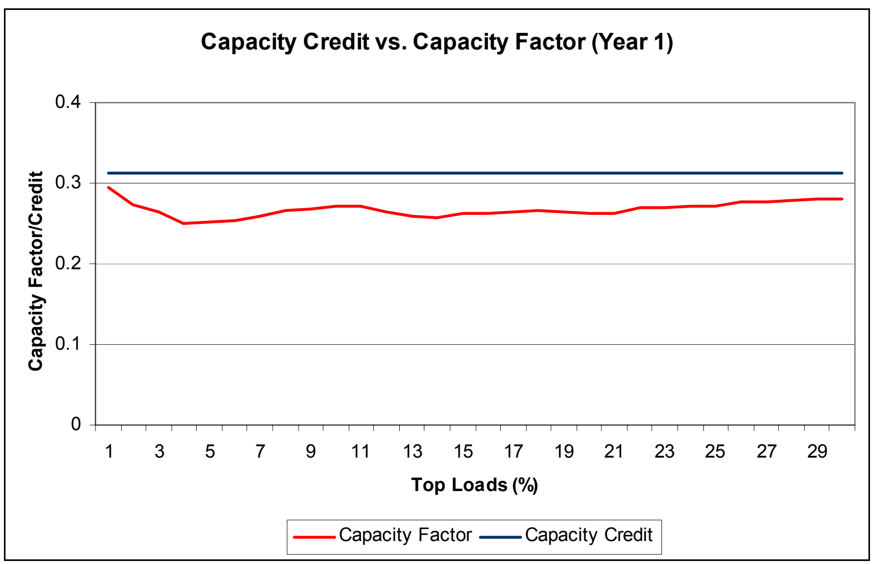


* The solar value is not recommended for adoption.

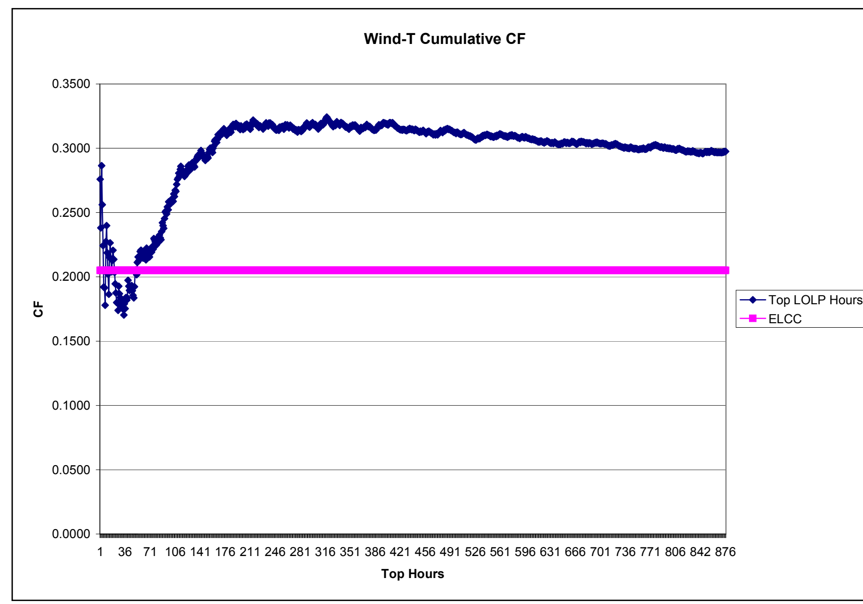
Current Efforts

Simplified Methodology

- Take cumulative capacity factor based on some combination of highest load and risk hours and correlate with ELCC values.
- Method has been successfully applied outside of California, but does not work well with California data
- Will continue to examine this issue.



Non-California Example



California: LOLP ranking with Wind (Tehachapi)

Solar ELCC

- Investigate discrepancy between perceived and calculated ELCC values.

Renewable Bids – Capacity Credit

- If there is not sufficient data for a proposed renewable plant
  - *Use "class average" for that technology and location until actual operating data is available*
- If data exists, use up to 3 years rolling average
- Use reliability model to calculate ELCC, or use simplified method if available

Established Renewable Generators

- Use 3-year rolling average capacity credit
- This amounts to a performance test
  - *When the rolling average declines the capacity credit also declines*
  - *When the rolling average increases the capacity credit also increases*

Established Renewable Generators

- Determine the monetary value of capacity ($/kW-year; to be supplied by CPUC)
- Apply the monetary value to the ELCC or approximation from either the class average (new sites) or rolling average (established sites)

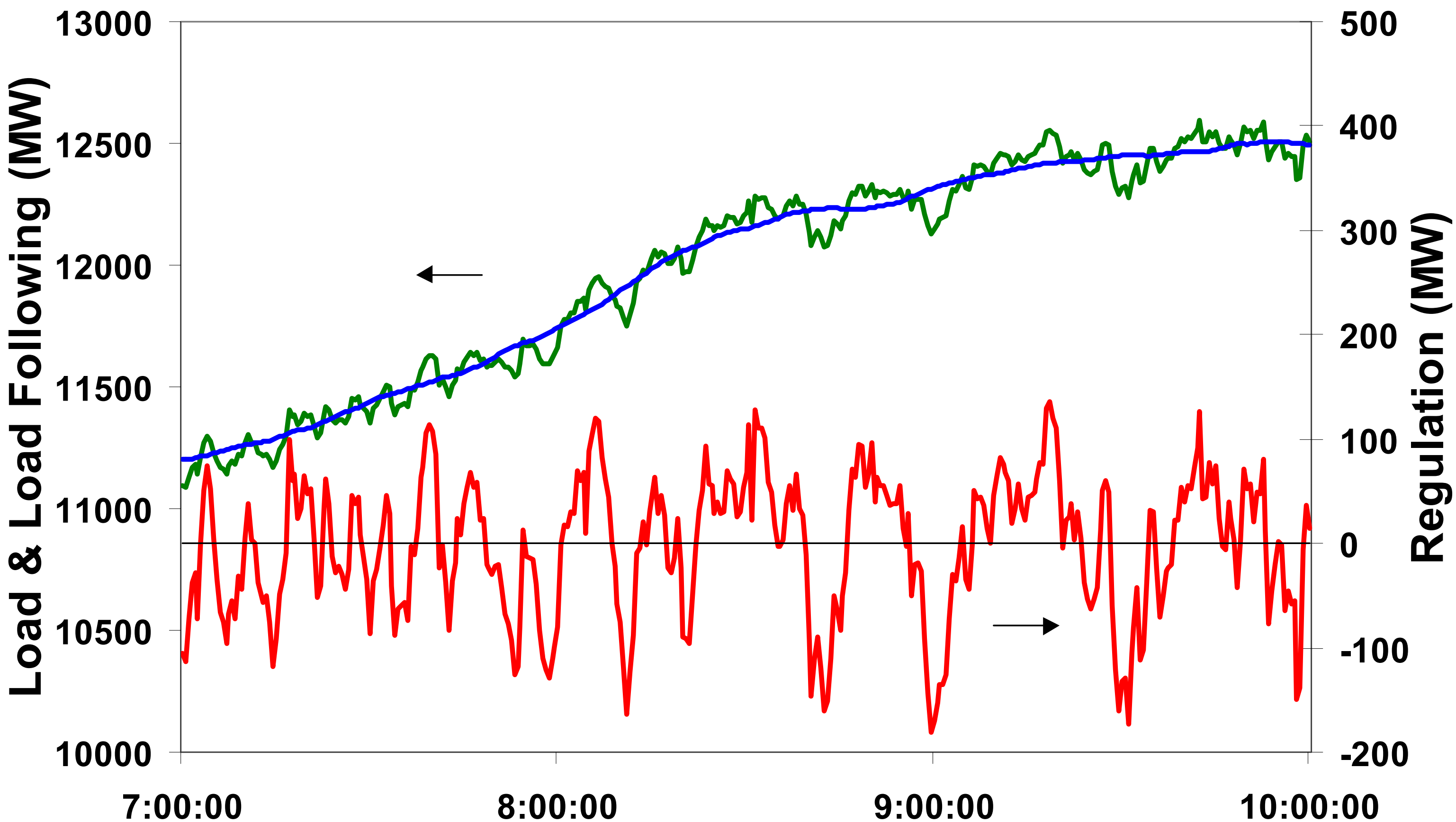
Recommendations

- CEC/CPUC utilize existing in-house reliability model for future capacity work
- Corroborate these results with more accurate CA data and CEC's model, including dis-aggregated renewable data
- Use ELCC and rolling 3-year average unless simpler approximations can be found
- Separate reliability study to look at the impact of maintenance timing on risk

Regulation and Load Following

Decomposition of Control Area Loads

Control area load & generation were decomposed into *base*, *load following*, and *regulation*.



Regulation & Load Following Characteristics

- Both address the time varying characteristic of balancing generation and load under normal operations
- The "system" only has to compensate for the aggregation

Regulation

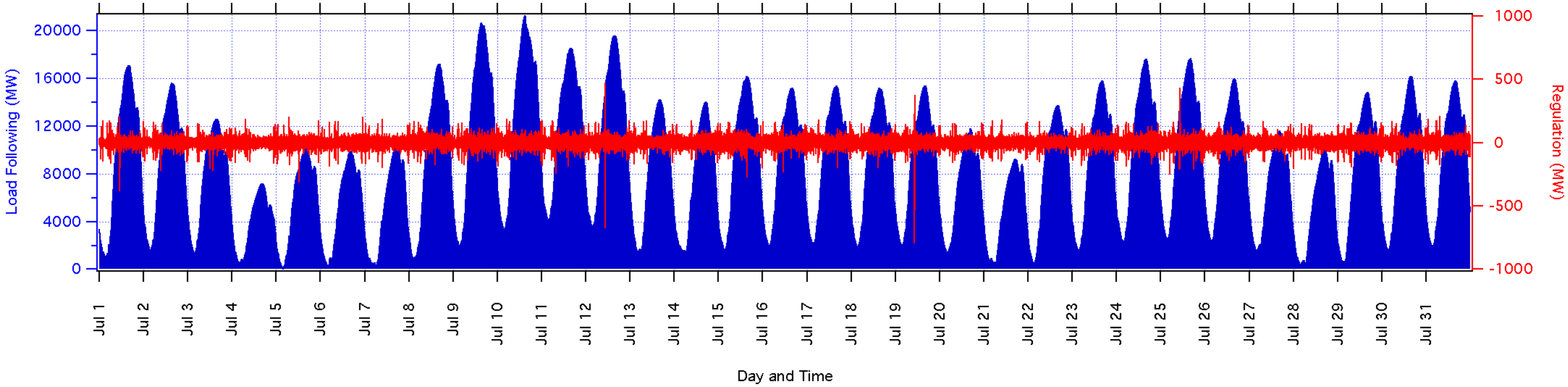
- Matches generation minute to minute
- Regulating units
  - *Online*
  - *Not fully loaded*
  - *Not at minimum loading*
  - *With automatic generation control*
  - *With ability to move rapidly (MW/minute)*
- Costs
  - *Degraded heat rate*
  - *Lost energy sales opportunity*
  - *Forced to be on line*
  - *Procured through regulation market*

Load following

- Longer term analogue to regulation
- Use of generation to meet hour-to-hour and daily variations in load
- Occurs over 10 minutes to hours
- FERC did not require in Order 888 tariffs
- Provided by hourly and sub-hourly energy markets

Regulation & Load Following Differ

	REGULATION	LOAD FOLLOWING
Patterns	*Random, uncorrelated*	*Largely correlated*
Generator control	*Requires AGC*	*Manual*
Maximum swing (MW)	*Small*	*10 – 20 times more*
Ramp rate (MW/minute)	*5 – 10 times more*	*Slow*
Sign changes	*20 – 50 times more*	*Few*



Regulation Analysis Results

Regulation Analysis Data Requirements

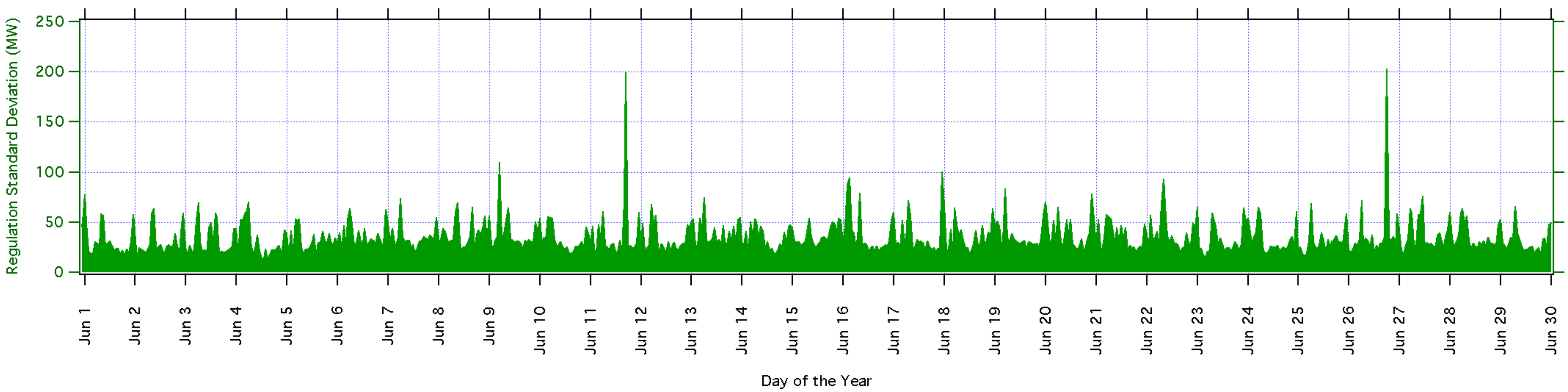
- One minute total system load data
- One minute resource generation data
- Hourly system regulation purchases
- Hourly system regulation price

Allocating Regulation Cost to Individuals

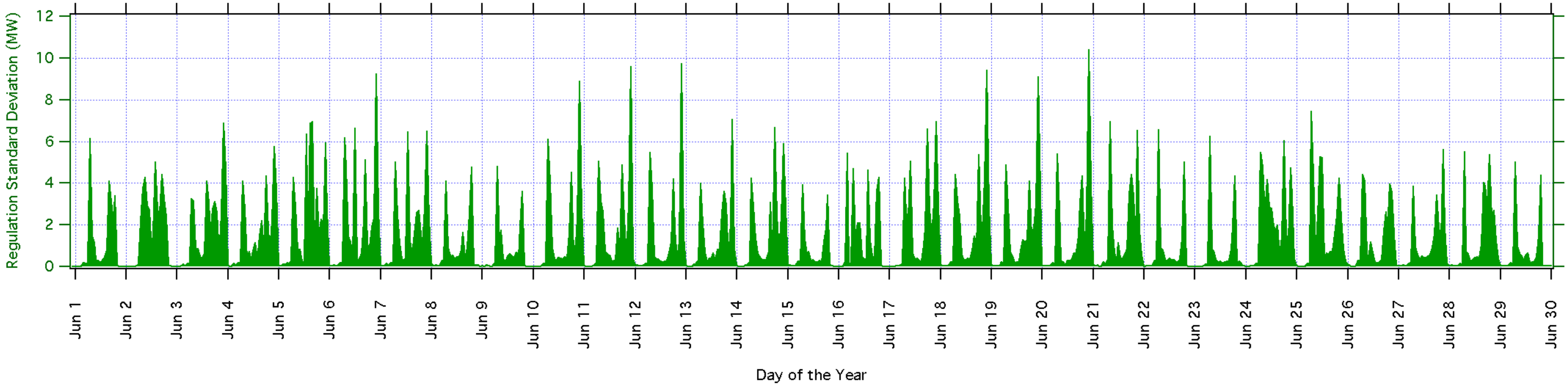
- Determine the hourly system regulation requirement.
  - *One minute data for total system load.*
  - *Separate regulation (capacity) from load following (energy).*
  - *Calculate hourly standard deviation values.*
- Determine the hourly individual regulation requirements.
- Allocate the individual hourly regulation requirements.
- Obtain the hourly system regulation purchase amount.
- Allocate the total regulation purchase to individuals.
- Obtain the hourly regulation price.
- Determine the hourly individual regulation cost.

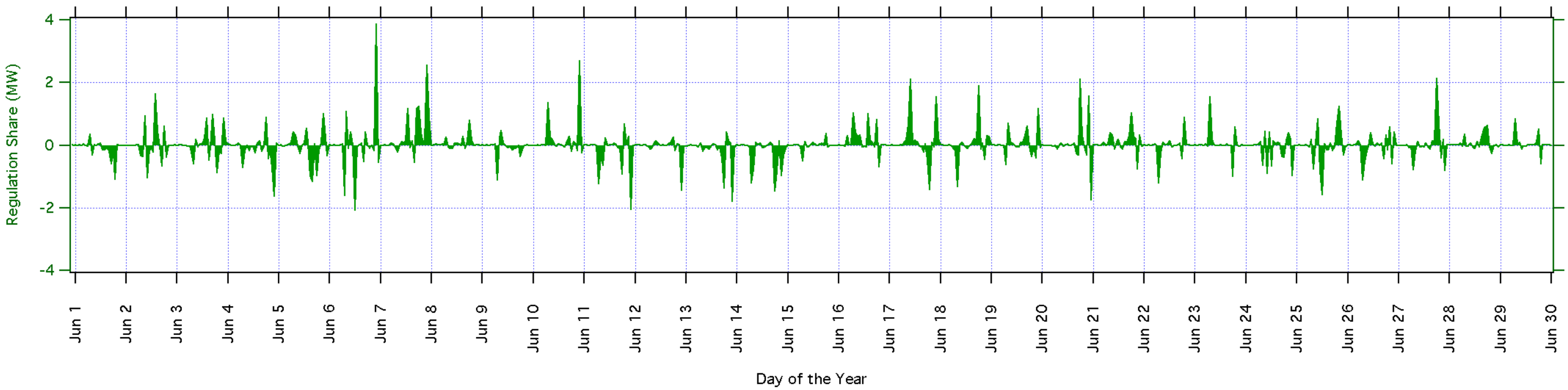
System Regulation Standard Deviation

- Calculate the average hourly standard deviation for regulation of the system (total load).
- These results were compared against actual purchases by CaISO and were used to allocate the regulation impact of each generator.

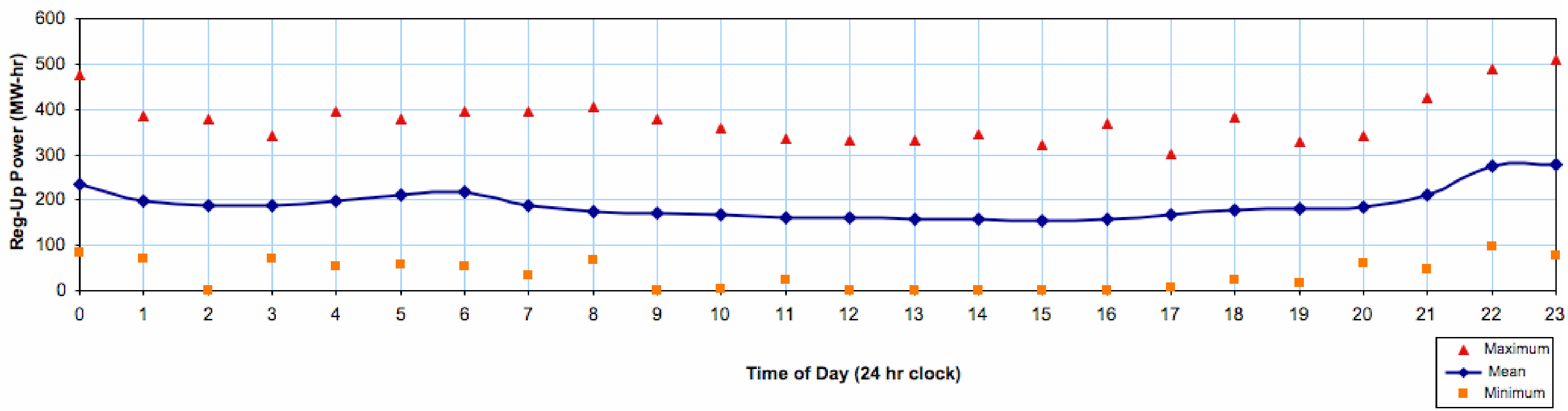


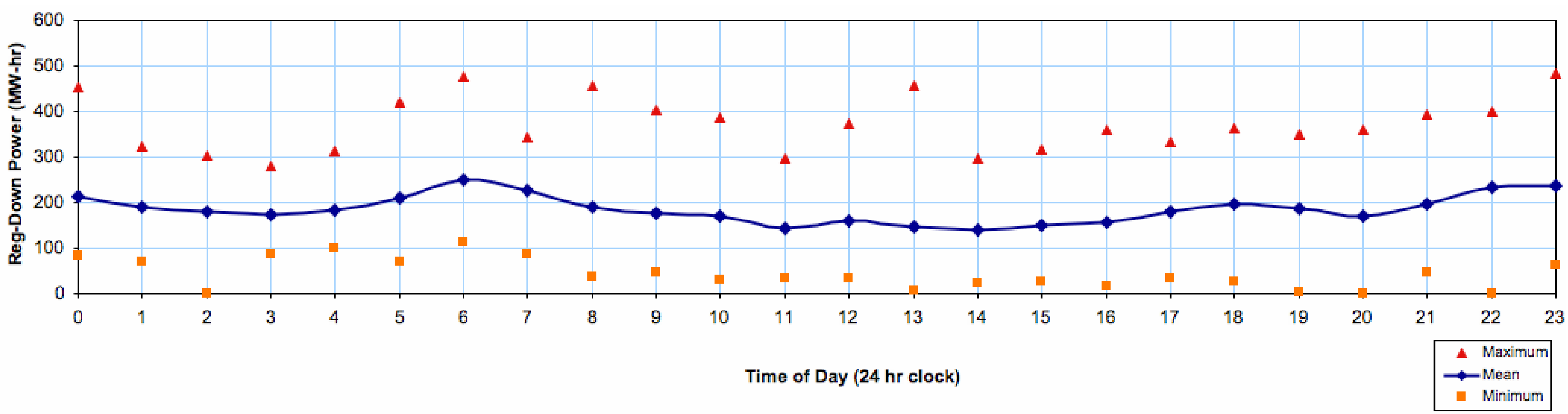
Solar Regulation Standard Deviation and Allocated Regulation Share





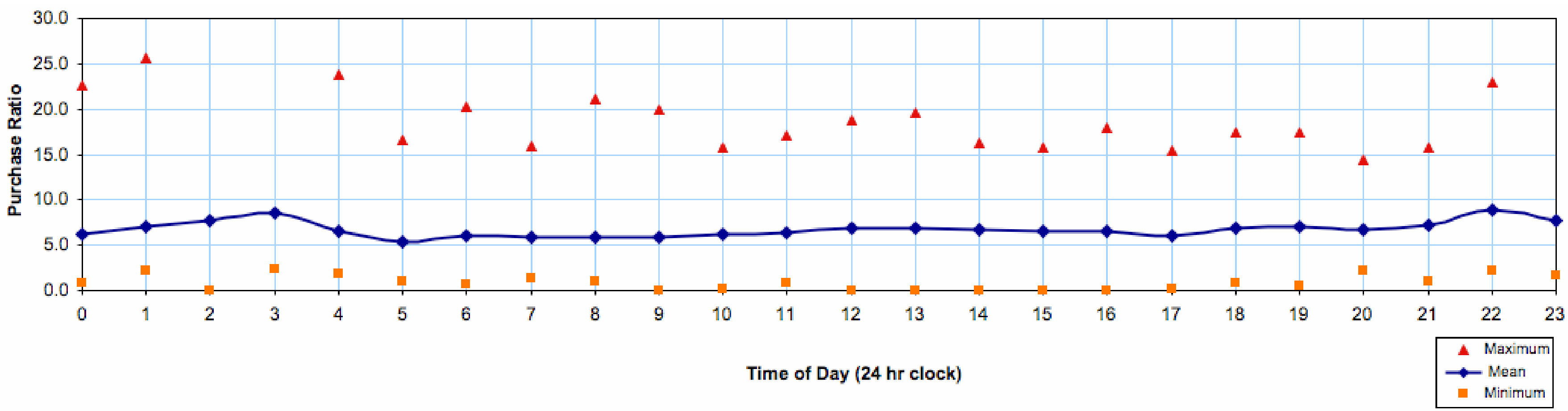
Actual Regulation Purchases



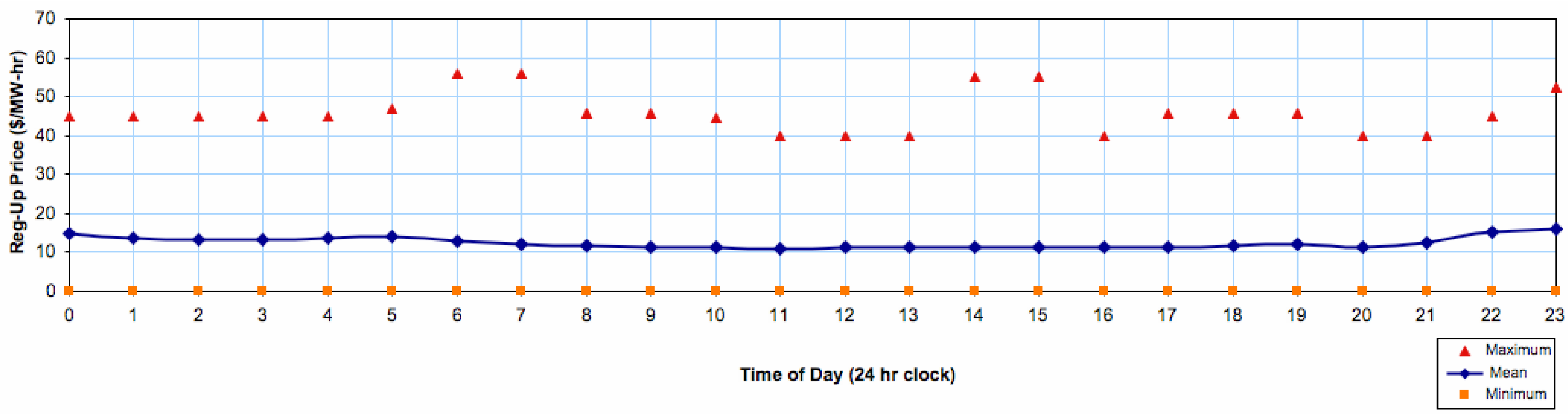


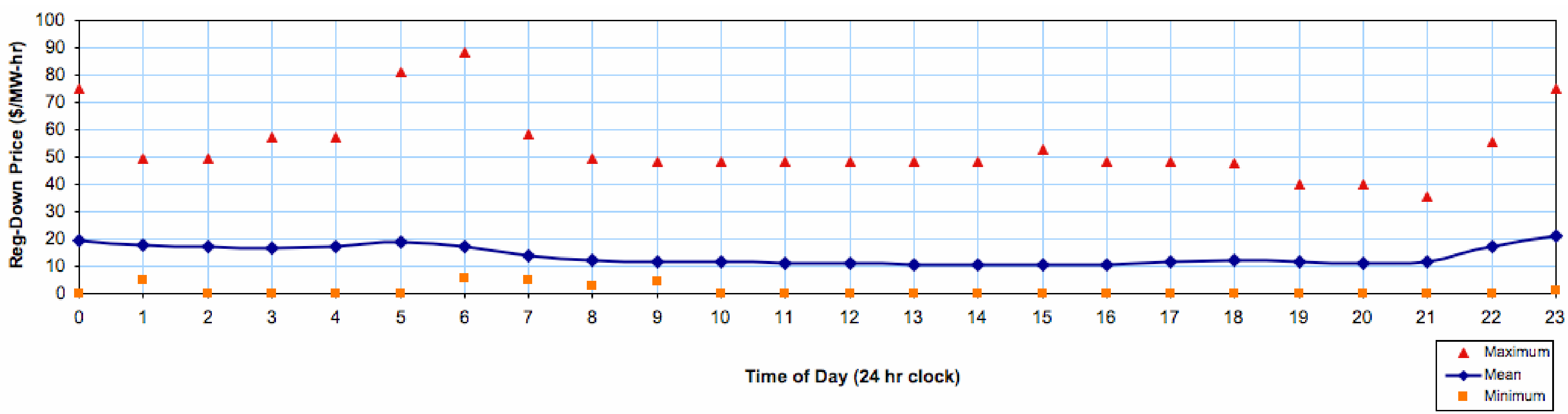
Regulation Purchase Ratio

- The regulation purchase ratio compares the actual purchase against the calculated standard deviation.
- The average annual purchase ratio was 6.5 for Reg-Up and 6.7 for Reg-Down.
- The purchase ratio was used to adjust the results from each resource of interest to actual data for each hour.

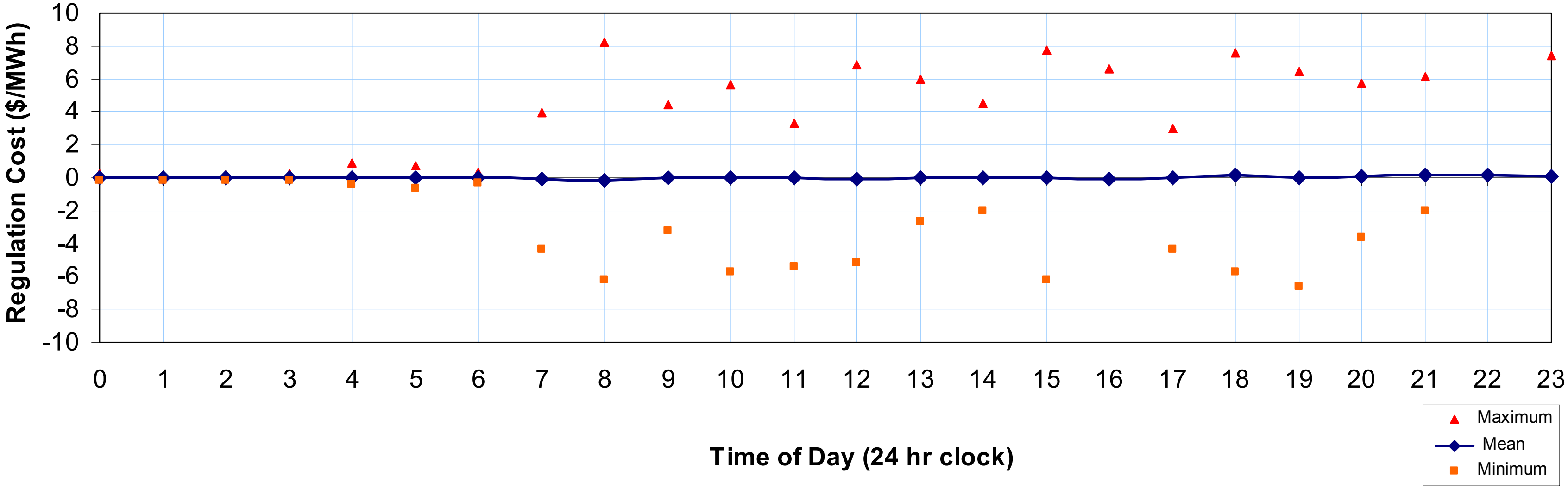


Actual Regulation Prices





Allocated Regulation Cost of Solar



Regulation Cost Results

- A negative value means there is a cost imposed on the system.
- A positive value means there is a benefit provided to the system.

Resource	Regulation Cost ($/MWh or mills/kWh)
Total Load	-0.42
Medium Gas	0.08
Biomass	0.00
Geothermal	-0.10
Solar	0.04
Wind (Altamont)	0.00
Wind (San Gorgonio)	-0.46
Wind (Tehachapi)	-0.17
Wind (Total)	-0.17

Prior Ancillary Services Studies

- A comparison of studies analyzing the cost of ancillary services for integrating wind energy
- Our study found a cost of $0.17/MWh

Study	Wind Penetration	Cost (per MWh)	Note
Xcel Energy	**3.5% (280 MW)**	**$2.00**	**Includes forecast error, load following reserves (capacity), and load following (energy). No hourly market, so there is a large day-ahead forecasting penalty.**
PacificCorp	**20%**	**$5.50**	**Study did not analyze regulation costs and assumed they were insignificant.**
BPA (Hirst)	**5.9%**	**$1.37 – $2.17**	**Like Xcel study, includes forecast error and load following. Forecasting error accounts for majority of cost.**
We Energies	**250 MW – 2000 MW**	**$1.90 - $2.92**	**Forecasting error dominated cost.**
PJM (Hirst)	**0.06% - 0.12%**	**$0.05 – $0.30**	**Examined regulation only and found results comparable to our study. Penetration is very low.**

Load Following Analysis Results

Load Following

- Deviations between the scheduled generation and the actual load requirements are compensated through purchases from the CaISO supplemental energy market.
- The system operator must compensate for aggregate scheduling error; individual errors must be viewed in the context of the full system.
- Market participants provide CaISO with bids for the hour ahead energy market and create the “stack” of available generators.
- The purpose of the load following analysis was to determine if the renewable generators affected the size or composition of the “stack” and therefore changed the cost for the load following service.

Is Load Following an Integration Cost?

- Supplemental energy market participants are paid for incremental and decremental energy.
  - *Failure to follow a schedule may generate INCs or DECs, but those will be settled by the market.*
  - *Those market costs are explicit.*
- If the renewable generators affect the size or composition of the “stack”, they change the cost for the load following service and incur an integration cost.

Method Required Minimal Data

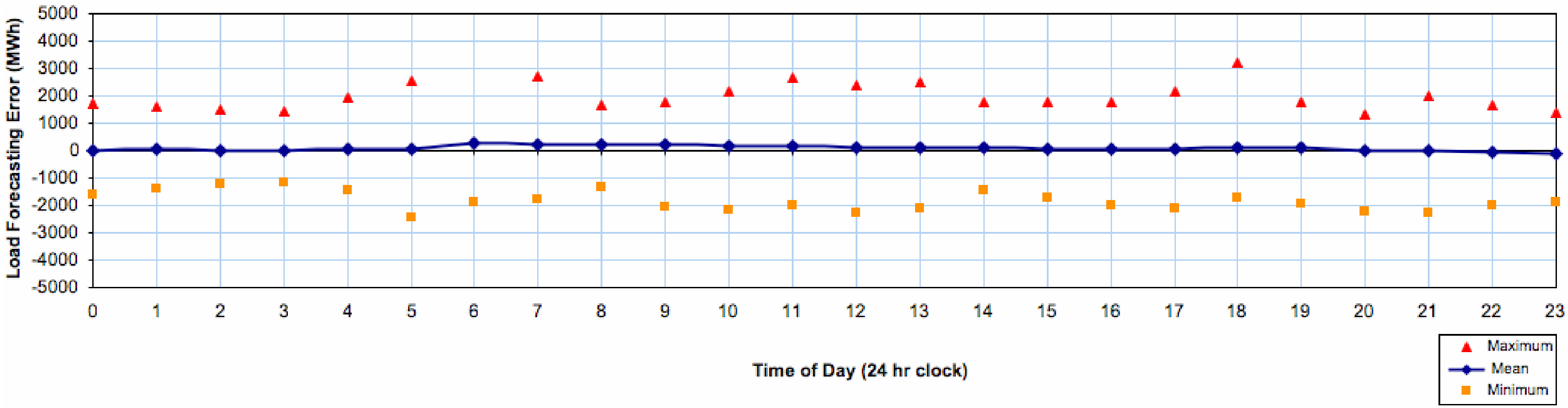
- Hourly system loads, schedules, and forecasts.
- Hourly renewable resource generation data.

Load Following Analysis

- Bids and schedules for the hour ahead market are provided 150 minutes ahead of time.
- The load following analysis used hourly average values of the 10 minute supplemental energy market data.
- Resource schedules for the hour ahead market were derived by using a simple, “naïve” persistence model,
- The load following analysis used two persistence models:
  - *Geothermal, biomass, and wind schedules were derived by simply shifting actual generation forward by 150 minutes.*
  - *Solar schedules were derived by shifting actual generation forward by 24 hours.*

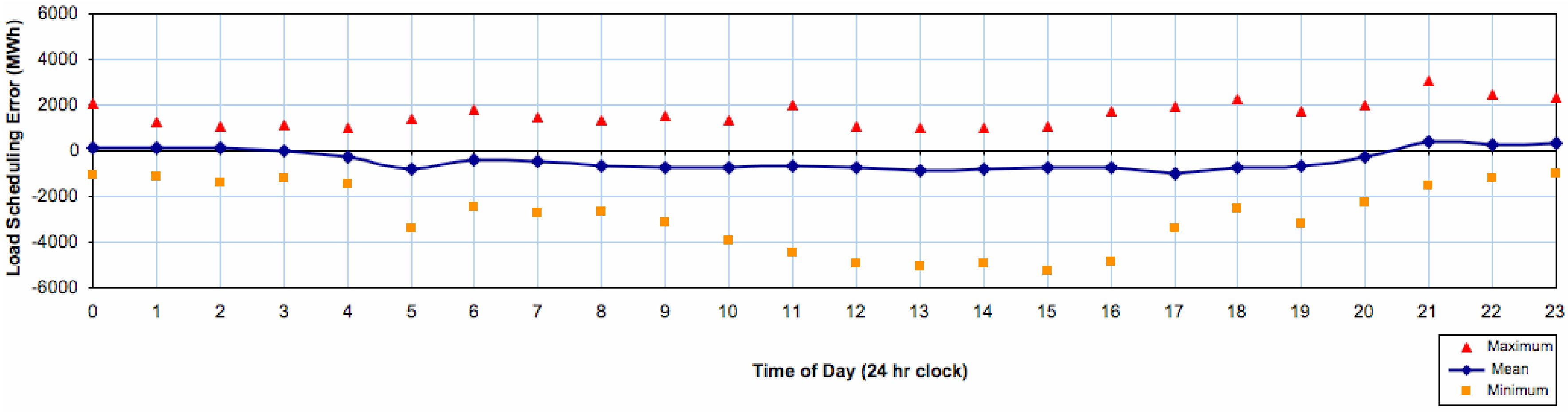
Forecast Hour Ahead Load

- CalSO provides a forecast of total system load for the hour ahead market.
- The forecast represents the best estimate of the generation required in the hour ahead market.
- The forecasted load is not equal to the scheduled load.
- The load forecasting error is equal to the forecast load minus the actual load.

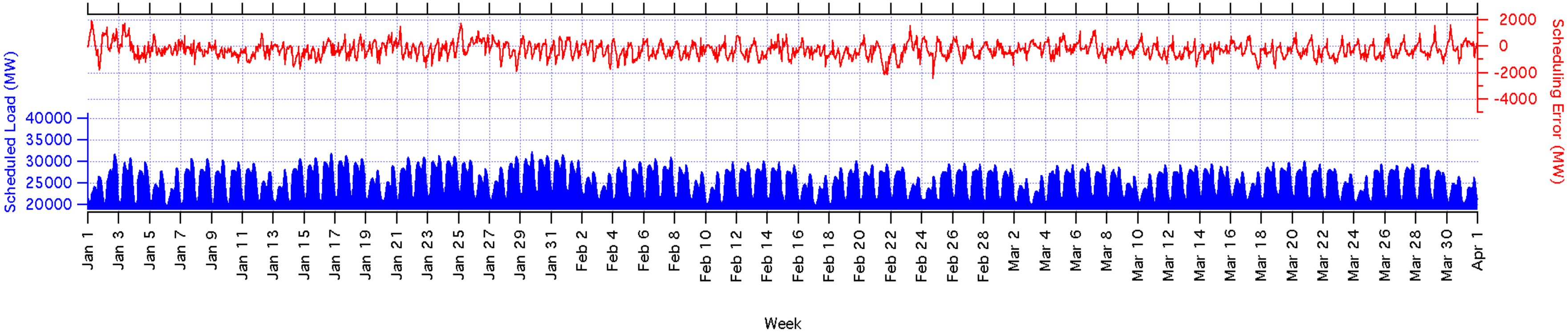


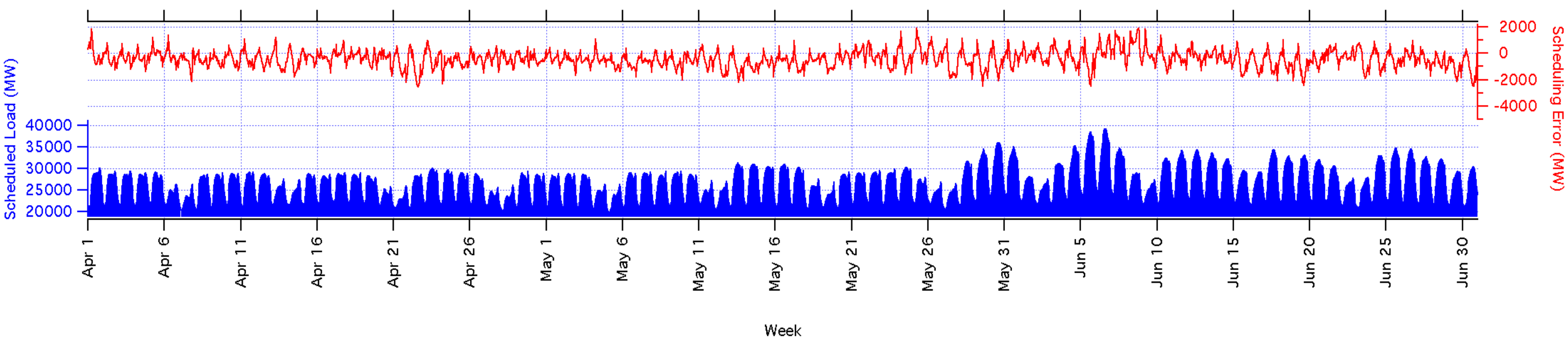
Scheduled Hour Ahead Load

- Hour ahead schedules are submitted to CalSO by the scheduling coordinators.
- The scheduled load is strongly biased relative to the actual load.
- Scheduled load can be as much as 5000 MW less than the actual load during some hours of the year.
- Scheduling bias is most negative during the afternoon peak and averaged -880 MW between noon and 6 pm.
- The load scheduling error is defined as the scheduled load minus the actual load.

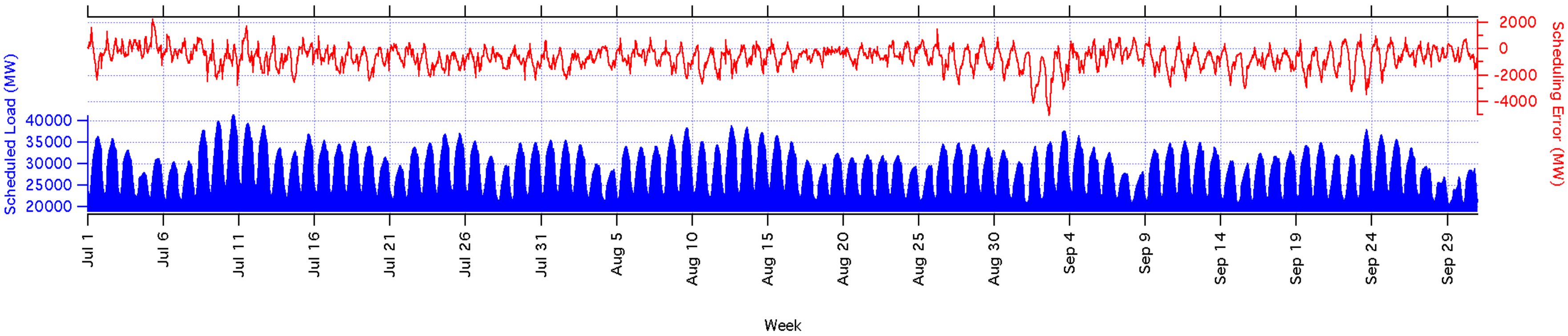


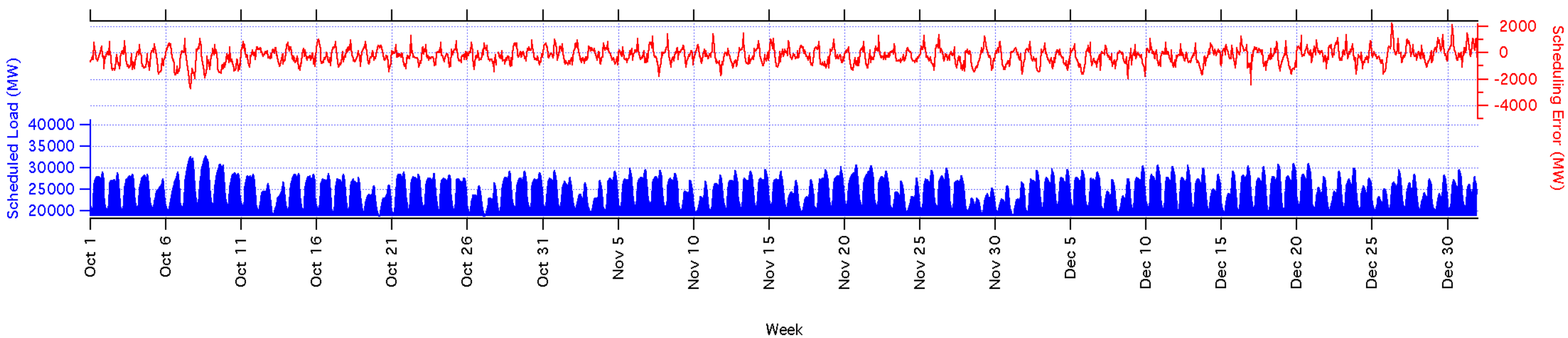
Scheduling Error





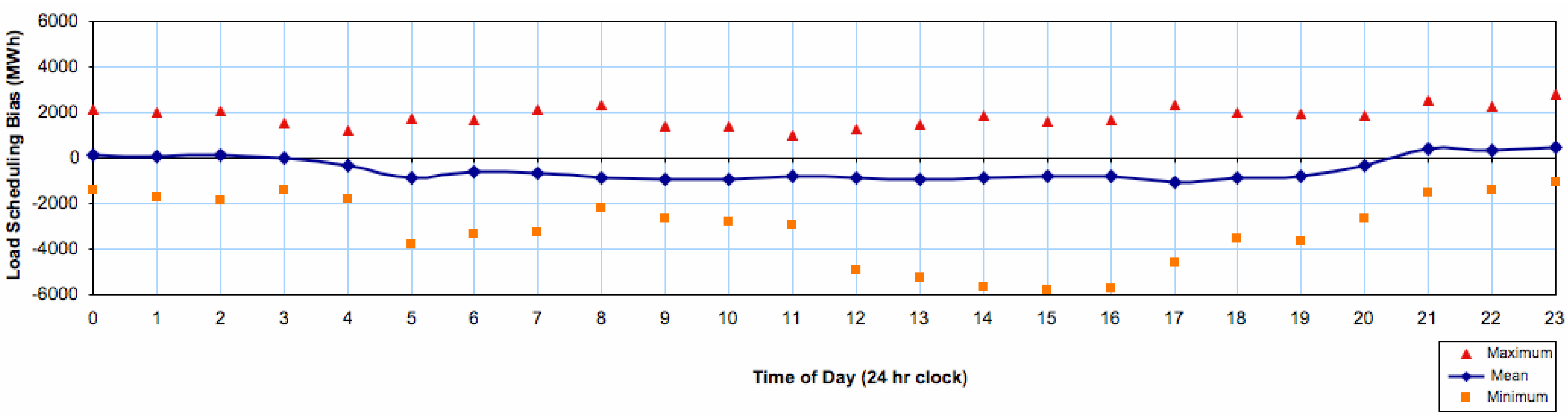
Scheduling Error



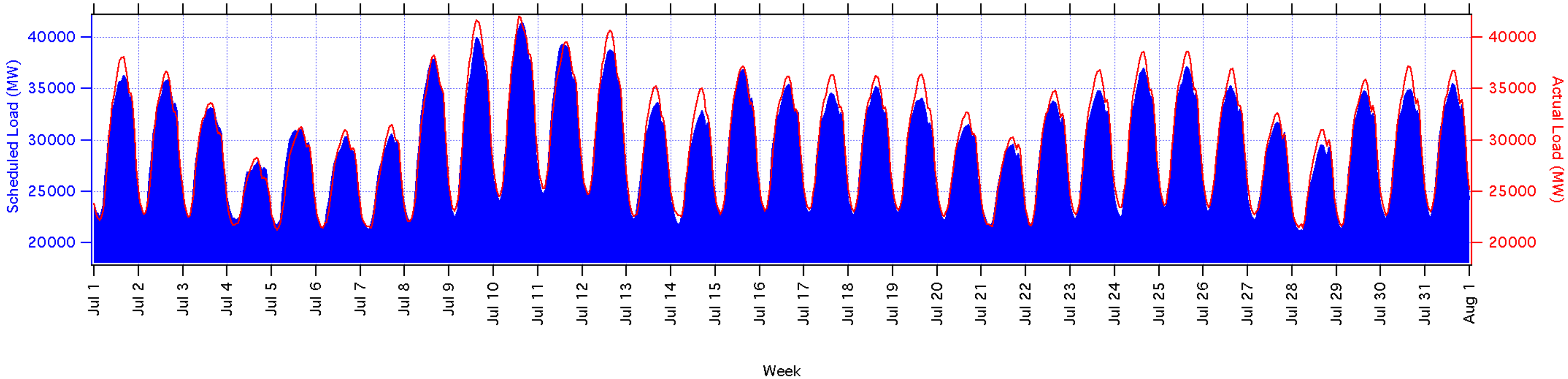


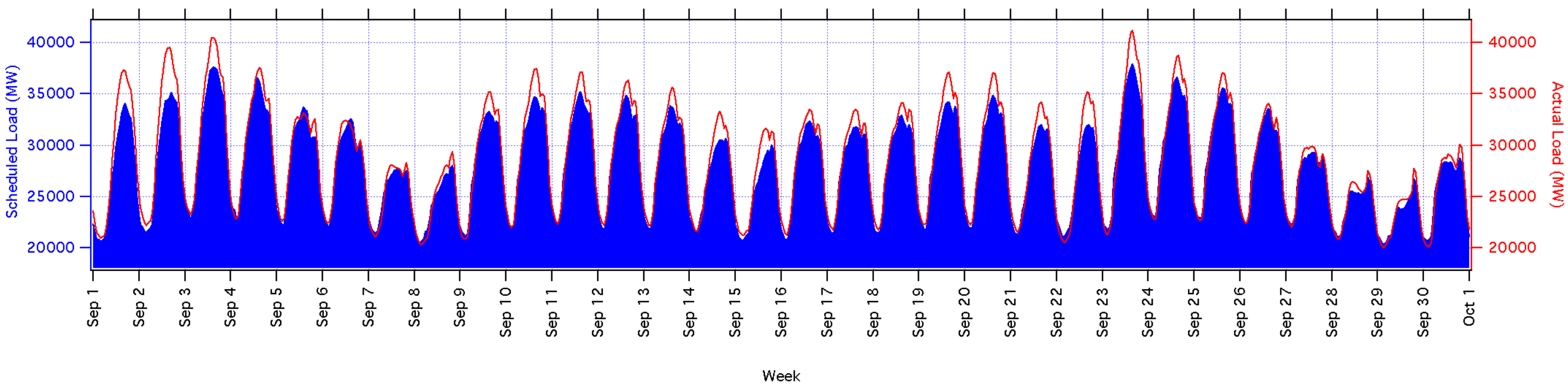
Scheduling Bias

- The scheduled load is strongly biased relative to the forecast load.
- The load scheduling bias is defined as the scheduled load (from the scheduling coordinators) minus the forecast load (from CaISO).
- The scheduling coordinators consistently schedule less generation than is needed according the load forecast by CaISO.
- The average scheduling bias between the peak hours of noon and 6:00 pm is -880 MW less than forecast.
- The average minimum scheduling bias during the peak hours is -5075 MW.



Scheduled Hour Ahead Load





Load Following Results

- Calculated the forecast error.
- Calculated the forecast error including the resource scheduling error.
- Compared to scheduling bias during peak hours from noon to 6 pm.
- Changes are small compared to the scheduling bias.
- Effect of renewables on stack appears negligible at this level of penetration.

	COMBINED FORECAST ERROR AND RENEWABLE SCHEDULING ERROR			
	Average Minimum		Average Maximum	
RESOURCE	MW	Compared to forecast error w/out Renewables (%)	MW	Compared to forecast error w/out renewables (%)
Forecast error without renewables	-1909	100%	2220	100%
Biomass	-1897	99%	2218	100%
Geothermal	-1878	98%	2221	100%
Solar	-1870	98%	2220	100%
Wind (Altamont)	-1909	100%	2272	102%
Wind (San Gorgonio)	-1898	99%	2226	100%
Wind (Tehachapi)	-1884	99%	2281	103%
Wind (total)	-1870	98%	2377	107%
Scheduling bias	-5076	266%	1747	79%

Load Following Recommendations

- The load following analysis indicates that the effect of renewable scheduling errors at existing levels of penetration is negligible compared to the scheduling bias.
- Scheduling bias is determined by the scheduling coordinators.
- We recommend that no load following cost adders be used for RPS bid evaluation in the near term.
- We recommend that additional analysis be conducted to determine the potential load following costs associated with higher levels of penetration.

Open Discussion

Feedback and Comments

- Website:
  - *http://cwec.ucdavis.edu/rpsintegration/*
- Mailing lists (subscribe via website):
  - *rpsintegration-workinggroup@cwec.ucdavis.edu*
    - an open mailing list for discussion of the development of the methodologies
  - *rpsintegration-announcements@cwec.ucdavis.edu*
    - an open mailing list announcing key events relevant to the study
- Formal comments:

California Energy Commission
Re: Docket No. 03-RPS-1078 and Docket No. 02-REN-1038
Docket Unit, MS-4
1516 Ninth Street
Sacramento, CA 95814-5504
E-mail:docket@energy.state.ca.us

Workshop Questions

1. Does the current timing of the three-phased approach pose any critical problems in using Phase I results for procurement at this time? If so, please indicate what specific problems are posed in using the Phase I results, and is there a way to resolve the problems in time to use the results for the procurement?
2. What changes should be made in the methodology to ensure that it can be used fairly and objectively in a procurement process and take into account maintenance, forced outages and contract?
3. Some parties have been concerned that the Phase I results are calculated from representative, but aggregated data sets for each of the technologies. How large is the error expected by using the representative, but aggregated data sets? What nonaggregated data sets can be made available for phase II and phase III analysis?

Workshop Questions

4. Phase I results provide a consistent method for evaluating "baseline equivalent load carrying capacity (ELCC)" by making assumptions on availability, maintenance and no special scheduling instructions. Comment on the effects of these assumptions on your operations and please propose alternative methods for evaluating the baseline.
5. Phase I report recommends rolling analysis to integrate newly available data and annual recalculation of ELCC and integration cost valuations. Is this adequate? If not, how often should these calculations be adjusted, and who should be responsible for the analysis?
6. The results provide baseline values for ELCC. What are specific issues with respect to the adoption of these results?